

**UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF MONTANA
BUTTE DIVISION**

<p>EVA LIGHTHISER; et al. Plaintiffs, v. DONALD J. TRUMP, in his official capacity as President of the United States; et al.</p> <p>Defendants.</p>	<p>Case No: CV-25-54-BU-DLC</p> <p>DECLARATION OF MICHAEL S. SAWYER</p>
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I, Michael S. Sawyer, hereby declare as follows:

1. I am one of the attorneys of record for the Defendants in the above-captioned action.
2. In June 2024, the Bureau of Land Management (BLM) began planning its lease sales for the first quarter of 2025. Attached as Exhibit A is a true and correct copy of a sample scoping letter showing when this planning process started. BLM Montana/Dakotas State Office, Dear Reader Letter for Quarter 1, 2025 Lease Sale (June 26, 2024), which is available at https://eplanning.blm.gov/public_projects/2032675/200620104/20114331/251014314/30-day%20Scoping%20Dear%20Reader%20Letter_signed.pdf.
3. On March 7, 2025, the Office of Surface Mining Reclamation and Enforcement published a Record of Decision for the Spring Creek Mine Mining Plan Modification for Federal Coal Leases MTM 94378 and MTM 110693. Attached as

Exhibit B is a Record of Decision, which is available at https://www.osmre.gov/sites/default/files/inline-files/20250307-SpringCreek_ROD_Signed_1.pdf. The Project Timeline states that the Mining Plan Modification was originally approved in 2012 and again in 2016. Ex. B, at 5.

4. The Environmental Protection Agency publishes a Global Greenhouse Gas Overview on its website. Attached as Exhibit C is a copy of that overview, which is available at <https://www.epa.gov/ghgemissions/global-greenhouse-gas-overview>.

5. On July 7, 2025, the Department of Energy published a Resource Adequacy Report on Evaluating the Reliability and Security of the United States Electric Grid. Attached as Exhibit D is a copy of that Resource Adequacy Report, which is available at <https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf>. The Report states that Power Plant “Retirements Plus Load Growth Increase Risk of Power Outages by 100x in 2030.” Ex. D, at 1.

6. On June 5, 2025, the National Oceanic Atmospheric Organization updated its webpage on Monthly Average Mauna Loa CO₂. Attached as Exhibit E is a copy of that update, which is available at <https://gml.noaa.gov/ccgg/trends/>.

7. On February 6, 2025, the National Aeronautics and Space Administration updated its webpage on climate change. Attached as Exhibit F is a copy of that website, which is available at <https://science.nasa.gov/climate-change/>.

I declare under penalty of perjury, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct.

Executed this 11th date of July, 2025, in Washington, D.C.

/s/ Michael S. Sawyer
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EXHIBIT A



United States Department of the Interior



BUREAU OF LAND MANAGEMENT
Montana/Dakotas State Office
5001 Southgate Drive
Billings, Montana 59101
<http://www.blm.gov/montana-dakotas>

June 26, 2024

In Reply Refer To:
Quarter 1, 2025 Competitive Sale

Dear Reader:

The Bureau of Land Management (BLM) received Expressions of Interest to sell Federal oil and gas leases in a future lease sale. The preliminary parcel list with recommended stipulations for the nominated parcels is posted on the BLM e-Planning website, for a 30-day scoping period for review starting on June 26, 2024. To be most useful, we should receive your comments before July 26, 2024.

If you have any comments or know of any issues that should be addressed in our analysis of the parcels, please provide comments using one of the following methods:

Electronic: BLM e-Planning website – <https://eplanning.blm.gov>
Advanced Search for NEPA # DOI-BLM-MT-0000-2024-0003-EA
Click “Documents”
Click “Comment on Document”

Mail: Bureau of Land Management
Montana/Dakotas State Office
Branch of Fluid Minerals
Attn: Hattie Payne
5001 Southgate Drive
Billings, MT 59101

Contact: Hattie Payne (701) 260-4997
hpayne@blm.gov

Before including your address, phone number, e-mail address, or other personal identifying information in your comment, be advised that your entire comment – including your personal identifying information – may be made publicly available at any time. While you can ask us in your comment to withhold from public review your personal identifying information, we cannot guarantee that we will be able to do so.

An Environmental Assessment will be available for a 30-day review beginning on August 27, 2024 at the link listed above. Prior to issuance of any leases, the Decision Record and FONSI will be finalized and posted for public review on our BLM e-Planning website. Please refer to the BLM e-Planning website at <https://eplanning.blm.gov/eplanning-ui/home>. Current and updated information about our EA, Lease Sale Notice, and corresponding information pertaining to this sale can be found at the link referenced above.

We appreciate your attention to this review and look forward to hearing from you.

Sincerely,

Andrew Gibbs
Chief, Branch of Fluid Minerals
Bureau of Land Management
Montana-Dakotas State Office

EXHIBIT B

**United States Department of the Interior
Office of Surface Mining Reclamation and Enforcement**

**Spring Creek Mine
Mining Plan Modification for
Federal Coal Leases
MTM 94378 and MTM 110693**

Record of Decision

EISX-010-08-000-1732112528

March 7, 2025

Prepared by:
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Office of Surface Mining Reclamation and Enforcement
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1.0 INTRODUCTION

On January 13, 2025, the U.S. Department of the Interior (DOI), Office of Surface Mining Reclamation and Enforcement (OSMRE) published a Notice of Availability of the *Final Environmental Impact Statement for the Spring Creek Mine Mining Plan Modification for Federal Coal Leases MTM 94378 and MTM 110693*, collectively referred to as the Lease by Application 1 (LBA1) tracts, to address deficiencies in the 2016 *Environmental Assessment for Spring Creek Mine Mining Plan Modification for Federal Coal Lease MTM 94378* (2016 LBA1 EA) identified by the United States District Court for the District of Montana (the court) (*WildEarth Guardians v. Haaland*, No. CV 17-80-BLG-SPW (D. Mont. 2021)).

The Final Environmental Impact Statement (EIS) addressed the deficiencies identified by the court and considered new information available in analyzing potential impacts to environmental resources that could result from the continued mining of Federal coal from the LBA1 tracts. Four alternatives were analyzed in this Final EIS: Alternative 1 - Proposed Action, Alternative 2 - Partial Mining Alternative, Alternative 3 - Accelerated Mining Rate Alternative, and Alternative 4 - No Action. The primary differences among the four alternatives are (1) remaining tons of recoverable LBA1 coal, (2) remaining years of LBA1 coal recovery, and (3) the remaining LBA1 area disturbance.

OSMRE issued a Notice of Intent to prepare an EIS on March 17, 2022, initiating a 30-day public scoping period. OSMRE issued a Notice of Availability for the draft EIS on September 4, 2024, initiating a 45-day public comment period, and hosted a public meeting in Hardin, Montana on September 24, 2024. The U.S. Environmental Protection Agency (EPA) published a Notice of Availability of the Final EIS in the *Federal Register* on January 10, 2025 (90 FR 2001), and OSMRE published its Notice of Availability on January 13, 2025 (90 FR 2744).

This Record of Decision (ROD) documents OSMRE's selected alternative. OSMRE will prepare and submit a Mining Plan Decision Document (MPDD) for the DOI Assistant Secretary for Land and Minerals Management (ASLM) with its recommendation for the

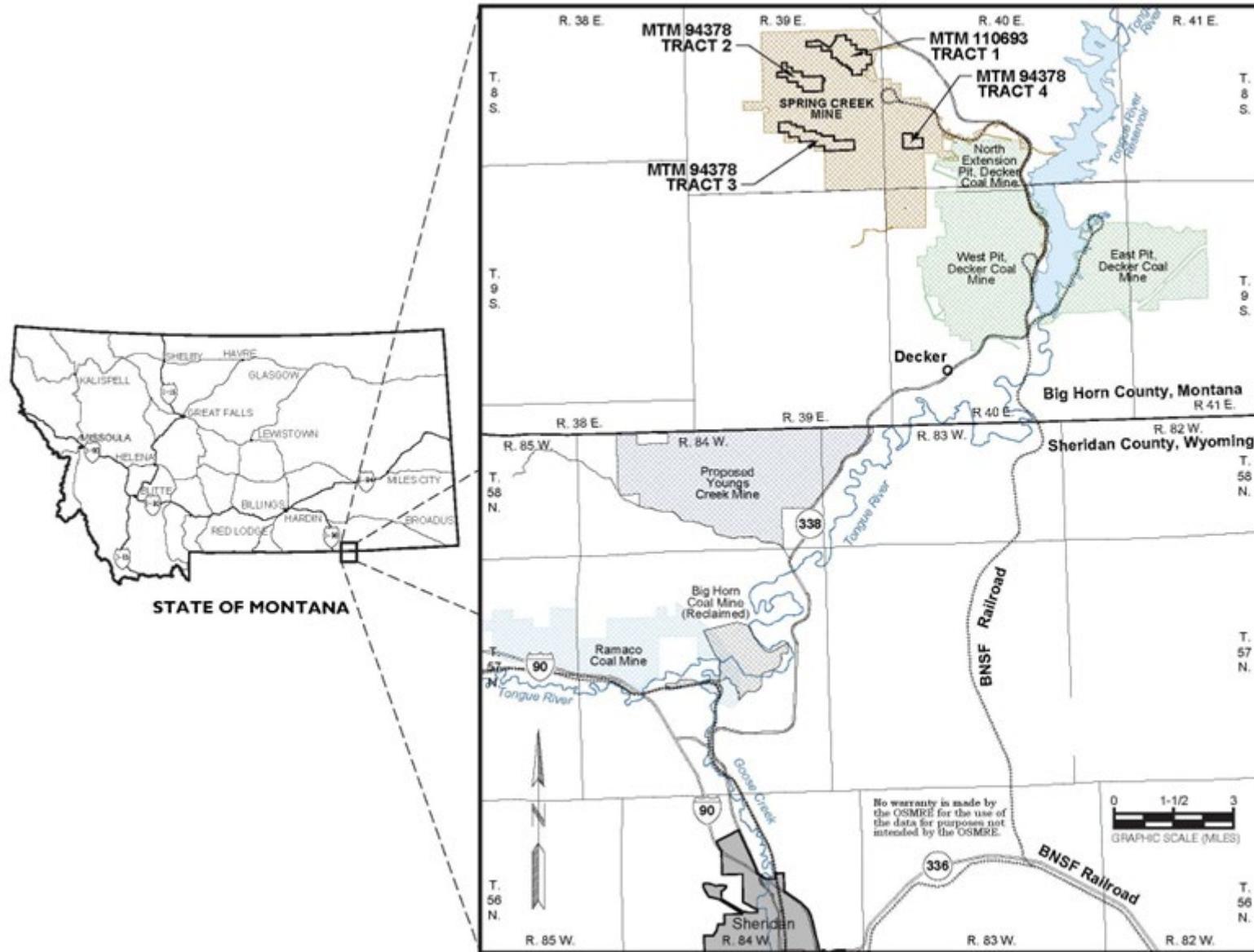
proposed mining plan modification. The ASLM will decide whether to approve, disapprove, or conditionally approve the modification.

1.1 Project Location and Background

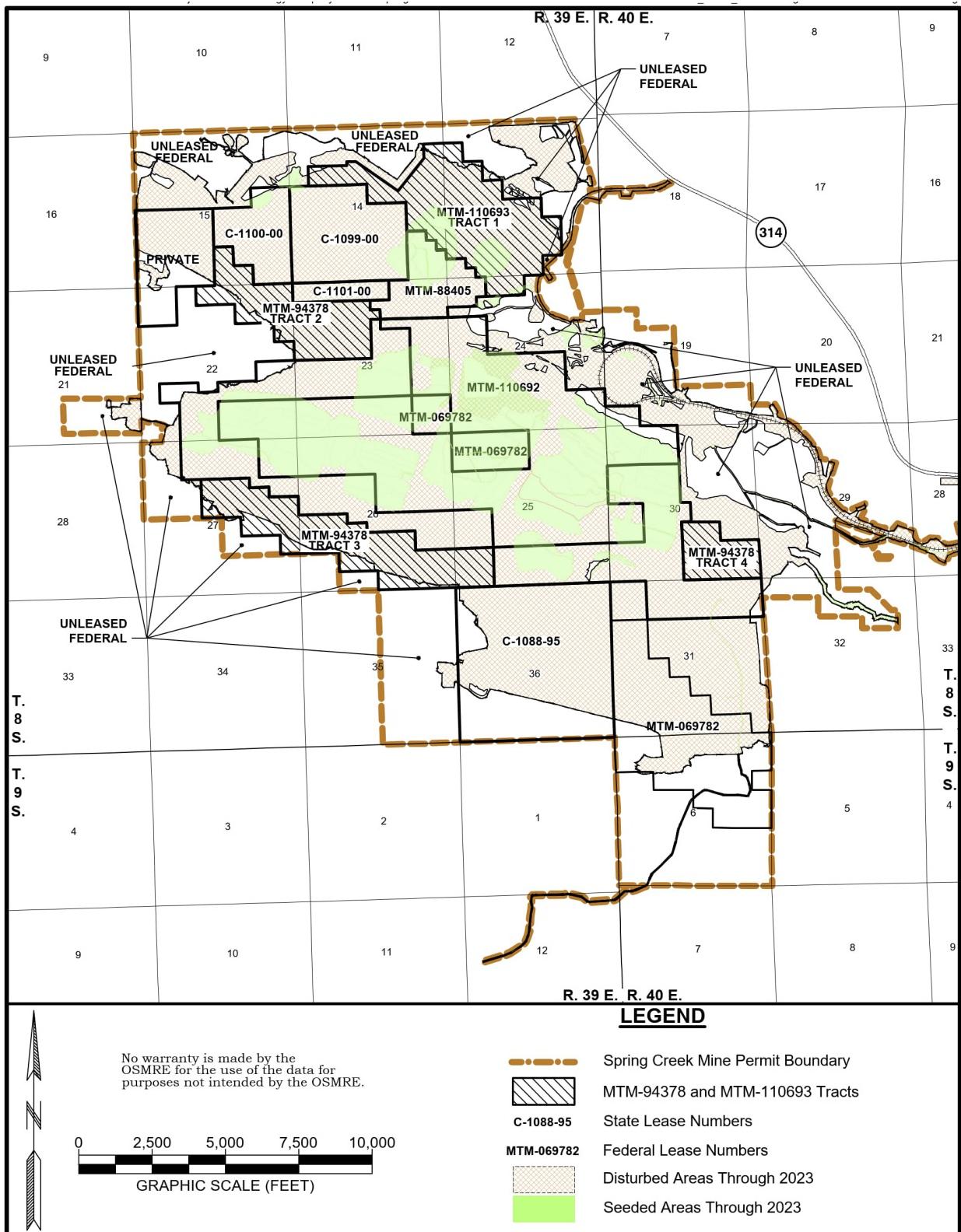
The Spring Creek Mine (SCM) is an existing surface coal mine in Big Horn County, Montana, approximately 32 miles north of Sheridan, Wyoming (**Map 1**). Coal has been mined on a commercial scale at the SCM since 1979. The SCM is currently operated by Navajo Transitional Energy Company, LLC (NTEC) following NTEC's acquisition in 2019 of substantially all the assets owned by Cloud Peak Energy, Inc., including the assets held by Spring Creek Coal, LLC. NTEC is a wholly owned limited liability company of the Navajo Nation.

The three tracts associated with Federal coal lease MTM 94378 and the tract associated with Federal coal lease MTM 110693 are referred to collectively as the LBA1 tracts. In addition to the LBA1 tracts, the SCM is permitted to mine coal from other non-LBA1 tracts, including Federal, state, and private leases within the permit boundary. The SCM recovers coal under 10 distinct coal leases (**Map 2**). There is approximately 63.4 million tons (Mt) of Federal, state, and private coal that cover approximately 971 acres outside of the area covered by the LBA1 tracts. Coal from the various leases is blended due to variability in quality to fulfill contracts.

Mining has been ongoing within the LBA1 tracts since the Federal mining plan modification was initially approved by the ASLM in 2012. For the analysis in the Final EIS, OSMRE used December 31, 2023, as the cutoff date for existing conditions at the mine because calculations and potential impacts are evaluated on an annual basis. As of December 31, 2023, approximately 63.3 Mt of the 103.2 Mt of LBA1 Federal coal had been recovered and 461.4 acres of the 627.9 acres had been disturbed within the four LBA1 tracts. As of December 31, 2023, approximately 39.9 Mt of LBA1 Federal coal remained, and approximately 162.5 acres of the LBA1 tracts had yet to be disturbed.



Map 1. General Location of the LBA1 Tracts



Map 2. Configuration of the LBA1 Tracts and Coal Leases within the Spring Creek Mine Permit Boundary

1.2 Project Timeline

An extensive timeline of this mining plan modification and its associated court orders is detailed in the Final EIS (**Section 1.3**).

2005—Spring Creek Coal, LLC, files a Lease by Application with the Bureau of Land Management (BLM) to lease four tracts of Federal coal (MTM 94378)

2006—BLM publishes a Notice of Availability of an Environmental Assessment (EA) for Spring Creek Coal Lease by Application, MTM 94378

2007—BLM issues a Finding of No Significant Impact (FONSI), offers MTM 94378 for competitive sale, accepts Spring Creek Coal, LLC’s bid, and issues the lease

2008—Spring Creek Coal, LLC, applies to Montana Department of Environmental Quality (MDEQ) for a revision to State Mining Permit (SMP) C1979012, and applies to OSMRE for a Federal mining plan modification

2011—MDEQ approves SMP C1979012 permit revision

2012—OSMRE adopts the 2006 BLM LBA1 EA, publishes a FONSI, and submits a MPDD to the ASLM recommending the approval of the mining plan modification

2012—ASLM approves the Federal mining plan modification; environmental groups file a challenge to the approval

2016—The court issues a decision holding that OSMRE had failed to fulfill its obligations under the National Environmental Policy Act (NEPA) and orders OSMRE to prepare an updated EA (*WildEarth Guardians v. OSMRE*, Civil Nos. 14-13-SPW & 14-103-SPW (D. Mont. 2016))

2016—OSMRE publishes the Spring Creek Mine Mining Plan Modification Environmental Assessment for Federal Coal Lease MTM 94378 (2016 LBA1 EA) and FONSI, and submits an MPDD to the ASLM recommending the approval of the mining plan modification

2016—ASLM approves the Federal mining plan modification; environmental groups file a challenge to the approval

2018—Spring Creek Coal, LLC applies to BLM to consolidate Tract 2, 3 and 4 of MTM 94378 into a logical mining unit; the remaining Tract 1 was segregated into a new lease MTM 110693 (collectively, the LBA1 tracts)

2019—NTEC acquires the SCM

2021—The court orders OSMRE to complete a remedial NEPA analysis that addresses identified deficiencies in the 2016 LBA1 EA, allowing for a deferred vacatur of the Federal mining plan modification until October 2, 2021; OSMRE requests and is granted an extension of the deferred vacatur until April 1, 2023

2022—OSMRE publishes a Notice of Intent to prepare an EIS and holds a public scoping meeting

2024—OSMRE requests and is granted an extension of the deferred vacatur until March 14, 2025; OSMRE publishes a Notice of Availability of the draft EIS and holds a public comment meeting

2025—OSMRE and the EPA publish a Notice of Availability of the Final EIS

1.3 Purpose and Need

OSMRE’s purpose in preparing the Final EIS is to fully analyze the environmental impacts from the Federal mining plan modification, with particular attention to addressing the deficiencies identified in the 2021 Court Order, so that OSMRE can make a recommendation to the ASLM to approve, disapprove, or conditionally approve the proposed Federal mining plan modification for the LBA1 tracts. The ASLM will decide whether the mining plan modification is approved, disapproved, or approved with conditions. Under the current Court Order, the deferred vacatur is set to expire on March 14, 2025.

1.4 Agency Authority and Actions

OSMRE is the lead agency for the Project. No Federal or state agencies, tribes, counties, municipalities, conservation districts, or non-government organizations indicated interest in participating as a cooperating agency on this project.

This ROD documents OSMRE’s selected alternative. Pursuant to 30 U.S.C. § 207(c) and 30 C.F.R. part 746, OSMRE will prepare and submit an MPDD to the ASLM with its

recommendation for the proposed mining plan modification. The ASLM will decide whether to approve, disapprove, or conditionally approve the modification.

1.5 Public Involvement

During the development of the Final EIS, OSMRE provided opportunities for public involvement and comment, including an initial 30-day scoping period, a virtual public scoping meeting, a 45-day public comment period on the draft EIS, and an in-person public comment meeting. OSMRE also mailed letters to Federal agencies, state agencies, tribes, counties, municipalities and conservation districts, non-government organizations, and individuals.

Comments received during the scoping and public comment process were reviewed to identify additional significant environmental issues for the Final EIS. Refer to **Appendix D** of the Final EIS for a description of the comments received on the draft EIS, and OSMRE’s responses to substantive comments.

2.0 U.S. District Court for the District of Montana Order

In 2021, the court found that OSMRE’s 2016 LBA1 EA failed to take a “hard look” at the indirect effects of coal transportation, non-greenhouse gas emissions, and greenhouse gas (GHG) emissions resulting from the proposed mining plan modification (*WildEarth Guardians v. Haaland*, No. CV 17-80-BLG-SPW (D. Mont. 2021)). OSMRE finds that the analysis in the Final EIS adequately addresses the deficiencies in the 2016 LBA1 EA identified in the Court Order, specifically:

2.1 Coal Transportation

Indirect and cumulative effects of diesel emissions, noise, vibrations, and coal dust emissions from rail cars based on the final destination and routes of SCM coal shipments are addressed in **Sections 4.4.3, 4.14, and 4.15** of the Final EIS.

2.2 Non-Greenhouse Gas Emissions

Indirect effects of non-greenhouse gas from downstream combustion emissions are addressed in **Section 4.4.4** of the Final EIS.

2.3 Greenhouse Gas Emissions

Effects related to the social cost of GHG emissions are addressed in **Section 4.4.5** of the Final EIS.

NEPA does not require an agency to quantify project impacts through a specific methodology, such as estimating the “social cost of carbon,” “social cost of methane,” or “social cost of greenhouse gases.” A protocol to estimate what is referenced as the “social cost of carbon” (SCC) associated with GHG emissions was developed by a Federal Interagency Working Group on the Social Cost of Greenhouse Gases (IWG).

Executive Order (EO) 14154, *Unleashing American Energy* (Jan. 20, 2025), however, disbanded the IWG and withdrew any guidance, instruction, recommendation, or document issued by the IWG, including the SCC protocol. Section 6(c) of EO 14154 states:

The calculation of the “social cost of carbon” is marked by logical deficiencies, a poor basis in empirical science, politicization, and the absence of a foundation in legislation. Its abuse arbitrarily slows regulatory decisions and, by rendering the United States economy internationally uncompetitive, encourages a greater human impact on the environment by affording less efficient foreign energy producers a greater share of the global energy and natural resource market. Consequently, within 60 days of the date of this order, the Administrator of the EPA shall issue guidance to address these harmful and detrimental inadequacies, including consideration of eliminating the “social cost of carbon” calculation from any Federal permitting or regulatory decision.

EO 14154 further directs agencies to ensure consistency with the guidance in OMB Circular A-4 of September 17, 2003, when estimating the value of changes in GHG emissions from agency actions.

In accordance with the EO, OSMRE would not normally include any estimates for the SCC for this action for multiple reasons. First, this action is not a rulemaking. Rulemakings are the administrative actions for which the IWG originally developed the SCC protocol. Second, EO 14154 clarifies that the IWG has been disbanded and its guidance has been withdrawn. Further, NEPA does not require agencies to conduct a cost-benefit analysis. Including an SCC analysis without a complete cost-benefit analysis, which would include the social benefits of the proposed action to society as a

whole and other potential positive benefits, would be unbalanced, potentially inaccurate, and not useful to foster informed decision-making. Any increased economic activity—in terms of revenue, employment, labor income, total value added, and output—that is expected to occur as a result of the proposed action is simply an economic impact, not an economic benefit, inasmuch as any such impacts might be viewed by another person as a negative or undesirable impact due to a potential increase in the local population, competition for jobs, and concerns that changes in population will change the quality of the local community. “Economic impact” is distinct from “economic benefit,” as understood in economic theory and methodology, and the socioeconomic impact analysis required under NEPA is distinct from a cost-benefit analysis, which NEPA does not require. In addition, many benefits and costs from agency actions cannot be monetized and, even if monetizable, cannot meaningfully be compared directly to SCC calculations for a number of reasons, including because of differences in scale (local impacts vs global impacts).

Finally, purported estimates of SCC would not measure the actual environmental impacts of a proposed action and may not accurately reflect the effects of GHG emissions. Estimates of SCC attempt to identify economic damages associated with an increase in carbon dioxide emissions—typically expressed as a one metric ton increase in a single year—and typically includes, but is not limited to, potential changes in net agricultural productivity, human health, and property damages from increased flood risk over hundreds of years. The estimate is developed by aggregating results across models, over time, across regions and impact categories, and across multiple scenarios. The dollar cost figure arrived at based on consideration of SCC represents the value of damages avoided if, ultimately, there is no increase in carbon emissions. But SCC estimates are often expressed in an extremely wide range of dollar figures, depending on the particular discount rates used for each estimate, and would provide little benefit in informing OSMRE’s or the ASLM’s decision. For these reasons, DOI has also rescinded its memorandum of October 16, 2024, entitled, “Updated Estimates of the Social Cost of Greenhouse Gases,” which had directed DOI bureaus to calculate SCC using the methodology contained in the EPA’s Final Rule of March 8, 2024, 89 Fed. Reg. 16,820.

However, notwithstanding the concerns outlined above, in this unique case, OSMRE was directed by the court to take a “hard look” at the costs of greenhouse gas emissions or risk having the mining plan modification approval vacated by the court. Because the SCC analysis in the Final EIS is complete and additional analysis would increase regulatory uncertainty for the mine in contravention of the policy articulated in Section 5(c) of EO 14154, OSMRE, in this ROD, is not revisiting the SCC analysis in the Final EIS. As explained in more detail below, in reaching its decision in the ROD, OSMRE weighed current policy considerations and concerns with the SCC outlined above when reviewing the Final EIS, as well as the fact that NEPA does not require an agency to quantify project impacts through a specific methodology, such as SCC.

3.0 OSMRE DECISION AND BASIS FOR DECISION

3.1 OSMRE Decision

OSMRE’s decision is to prepare and submit to the ASLM a MPDD recommending the approval of the proposed Federal mining plan modification, analyzed as Alternative 1 in the Final EIS, because this alternative best supports the purpose and need for the proposed action, the goals of the applicant, and national policy to encourage energy exploration and production on Federal lands and waters. OSMRE has based its decision to select Alternative 1, the Proposed Action, on a thorough review of the Final EIS, public input, consultation with Federal, state, and local regulatory agencies, and consultation with affected tribes. This section describes the relevant factors considered and balanced by OSMRE in reaching its decision.

OSMRE verifies that, in reaching its decision, it has complied with the requirements of NEPA, including the Department’s regulations and procedures implementing NEPA at 43 C.F.R. part 46 and Part 516 of the Departmental Manual. All stakeholders’ concerns and comments during the NEPA process have been satisfactorily addressed. OSMRE’s decision to select Alternative 1, the Proposed Action, will be implemented through issuance of this ROD. OSMRE’s MPDD will recommend to the ASLM that the Proposed Action be approved, without conditions.

3.2 Description of the Selected Alternative: Alternative 1 – Proposed Action

Under Alternative 1 - Proposed Action, the SCM would be authorized to mine the remaining 39.9 Mt of coal within the LBA1 tracts in accordance with the life of mine (LOM) mining sequence outlined in the approved MDEQ SMP C1979012. Under the Proposed Action, it is assumed that the remaining LBA1 tracts' coal would be mined and approximately 162.5 acres would be disturbed over a 16-year LOM.

As described in Section 1.1, mining has been ongoing within the LBA1 tracts since the Federal mining plan modification was approved in 2012. If approved, the Proposed Action would continue to mine the remaining 39.9 Mt of Federal coal, which would be shipped primarily to domestic industrial customers, as well as foreign markets. In the U.S., coal is transported by rail from the SCM to power plants in Washington, Arizona, Minnesota, and Michigan. Coal is also transported by rail to terminals in Wisconsin and Canada for vessel transport.

Following the completion of mining operations, the SCM will return the land to its approved postmining land uses (grazing, wildlife habitat, pastureland, and cropland) by adhering to the Reclamation Plan in SMP C1979012.

3.3 Environmentally Preferred Alternative: Alternative 4 – No Action

Under Alternative 4 - No Action, the Federal coal remaining within the LBA1 tracts as of March 14, 2025 (U.S. District Court for the District of Montana Order CV 17-80-BLG-SPW) would not be recovered. If the mining plan is not approved by the ASLM by the March 14, 2025, deadline, SCM would be unable to continue mining Federal coal within the LBA1 tracts or complete its required reclamation commitments within the boundaries of the LBA1 tracts. This alternative assumes that the SCM would apply for and receive all appropriate approvals to fully reclaim any disturbed areas in accordance with the Surface Mining Control and Reclamation Act of 1977 (SMCRA) and its current approved mining and reclamation permit.

The No Action alternative was identified in both the draft and Final EIS as the environmentally preferable alternative because it would cause the least amount of additional adverse environmental effects from the production or combustion of the remaining LBA1 tracts coal. Moderate direct and indirect negative socioeconomic

effects of a reduced LOM would be partially offset by the continued operation in other portions of the SCM, which has approximately 63.4 Mt of permitted non-LBA1 Federal, state, and private coal remaining. The No Action alternative was not selected for OSMRE's recommendation decision because it does not meet the purpose and need, and it does not align with current national policy to encourage energy exploration and production on Federal lands and waters. EO 14154 Sec. 2(a).

3.4 Other Alternatives Considered

A total of four alternatives were analyzed in the Final EIS. The primary differences among the four alternatives are: (1) remaining tons of recoverable LBA1 coal; (2) remaining years of LBA1 coal recovery; and (3) the remaining LBA1 area disturbance. Other alternatives were considered but eliminated from detailed analysis for the reasons discussed below.

3.4.1 Alternative 2 – Partial Mining

Under Alternative 2 - Partial Mining, ASLM approval of the mining plan modification for the LBA1 tracts would end after an approximate five-year term, and, if the operator would like to continue mining beyond the initial 5-year term, the operator would be required to apply for an additional mining plan modification, which OSMRE would review under the circumstances that exist in the future. During the five-year term, approximately 19.3 Mt of coal would be mined from the LBA1 tracts and approximately 78.5 acres would be disturbed. Under this alternative, any mining of the LBA1 tracts after this date would require a new application from the mine requesting permission to mine the remaining LBA1 Federal coal, new analysis by OSMRE, a new recommendation from OSMRE to ASLM, and a new mining plan modification approval from ASLM.

The Partial Mining alternative was identified in the Final EIS as the preferred alternative. Although the final mining plan modification decision remains with the ASLM, since the publication of the Final EIS on January 13, 2025, OSMRE has reevaluated the Partial Mining alternative and determined that it is not in alignment with current national policy considerations. OSMRE does not recommend this alternative to the ASLM.

Most notably, the January 20, 2025, EO 14154 (*Unleashing American Energy*), declared that it is the policy of the United States “to encourage energy exploration and production on Federal lands and waters . . . in order to meet the needs of our citizens and solidify the United States as a global energy leader long into the future.” EO 14154 Sec. 2. The EO directed the heads of all agencies to identify agency actions “that impose an undue burden on the identification, development or use of domestic energy resources - - with particular attention to oil, natural gas, coal, hydropower, biofuels, critical mineral, and nuclear energy resources. . .” *Id.* at Sec. 3. OSMRE finds that the recommendation of the Partial Mining alternative would constitute an agency action that imposes an “undue burden on the identification, development, or use of domestic energy resources” because it would limit mining Federal coal within the LBA1 tracts at SCM to five years, create significant uncertainty for NTEC and SCM about whether and how it could continue mining beyond the five-year approval period, and place an unnecessary barrier on the development of affordable energy resources in the United States. Further, the Secretary of the Interior issued Secretary’s Order (SO) 3418 on February 3, 2025, to implement provisions of EO 14154. That order, in part, directs the Department to focus on improving energy permitting, development, and production by removing regulatory impediments. As such, OSMRE finds that the Partial Mining alternative is inconsistent with EO 14154 and SO 3418, and it would create uncertainty for NTEC and the SCM about whether it would be authorized to continue mining beyond the initial 5-year approval period. OSMRE has decided not to select the Partial Mining alternative as its recommendation to ASLM.

3.4.2 Alternative 3 – Accelerated Mining Rate

Under Alternative 3 - Accelerated Mining Rate, the agency assumed that the remaining 39.9 Mt of coal would be mined from the LBA1 tracts at a rate of 18 Mtpy. Using this higher annual production rate, mining would continue for another 2.2 years within the LBA1 tracts. Approximately 162.5 acres, the same as the Proposed Action, would be disturbed under this alternative.

The Accelerated Mining Rate alternative was included in the alternatives analysis in the Final EIS because it was originally analyzed as the Proposed Action in the 2016 LBA1 EA and because it provided an opportunity to understand how changing the rate

of mining would change the duration and intensity of impacts. The Accelerated Mining Rate alternative was not selected for OSMRE's recommendation decision because, based on current coal market conditions, it would not be feasible for the SCM to mine the remaining LBA1 tract coal at the accelerated rate. Additionally, if SCM is operating in accordance with its approved mining plan and MDEQ permit, the rate of mining is an NTEC business decision, not a regulatory one.

3.4.3 Alternatives Considered but Eliminated from Detailed Analysis

OSMRE considered additional alternatives that were not analyzed in detail in the Final EIS (Final EIS Section 2.3). OSMRE concluded that there are no other reasonable action alternatives to the Proposed Action that would reduce or eliminate adverse environmental effects and meet the agency's purpose and need.

3.5 Basis for Decision

3.5.1 Environmental Considerations

OSMRE's decision considered the environmental effects of each alternative. Alternative 4, the No Action alternative, was identified in the draft and Final EIS as the environmentally preferable alternative because, based on the environmental analysis in the Final EIS, it would cause the least damage to the biological and physical environment. OSMRE determined that implementation of Alternative 2, the Partial Mining alternative, would not significantly reduce the intensity the environmental effects resulting from Alternative 1, the Proposed Action. Alternative 3, the Accelerated Mining Rate alternative, while remaining technically unfeasible due to current market conditions, would increase the intensity of impacts resulting from the proposed action.

All direct and indirect impacts, including their intensities, are described fully in **Chapter 4** of the Final EIS, and cumulative impacts are described in **Chapter 5** of the Final EIS.

Finding

OSMRE finds that the decision to select Alternative 1 considers the environmental analysis described in Chapters 4 and 5 of the Final EIS. While Alternative 1 is not the

environmentally preferable alternative and will result in some direct, indirect, and cumulative environmental impacts, Alternative 1 is the alternative that best meets the project's purpose and need, as well as current national policy considerations.

3.5.2 Economic Considerations

OSMRE's decision considered the economic effects of each alternative. Alternative 1, the Proposed Action, and Alternative 3, the Accelerated Mining Rate alternative, would extend the duration of employment for current employees and extend the economic benefits related to mining the Federal coal, including both state and Federal revenues. Alternative 3, however, would extend the employment benefits for a much shorter duration than Alternative 1. Alternative 2, the Partial Mining alternative, would extend the employment and economic benefits for the five-year term of approval, but beyond that term, economic impacts would be uncertain. Alternative 4, the No Action alternative, would not result in the employment or economic benefits associated with the SCM coal mining operations on the LBA1 tracts.

Finding

Direct and indirect socioeconomic impacts are described in **Section 4.17** of the Final EIS, and cumulative socioeconomic impacts are described in **Section 5.2.14** of the Final EIS. OSMRE finds that the decision to select Alternative 1 was based in part on the information contained in these sections on the direct, indirect, and cumulative socioeconomic impacts of this alternative as compared to other alternatives.

3.5.3 Essential Considerations of National Policy

In accordance with section 101(b) of NEPA, in addition to the environmental and economic considerations summarized above, OSMRE's decision included essential considerations of national policy, including:

3.5.3.1 *Unleashing American Energy*

EO 14154 and SO 3418 (*Unleashing American Energy*), direct Federal agencies and DOI bureaus to protect national economic, security, and military preparedness by ensuring that an abundant supply of reliable energy is readily accessible in every State and territory of the United States; to ensure that all regulatory requirements related

to energy are grounded in clearly applicable law; and to ensure that the global effects of a rule, regulation, or action shall, whenever evaluated, be reported separately from its domestic costs and benefits, in order to promote sound regulatory decision making and prioritize the interests of the American people; and to guarantee that all executive departments and agencies provide opportunity for public comment and rigorous, peer-reviewed scientific analysis.

3.5.3.2 Prioritizing Accuracy in Environmental Analyses

EO 14154 requires Federal agencies to adhere to only the relevant legislated requirements for environmental considerations and requires agencies to use the most robust methodologies of assessment at their disposal and shall not use methodologies that are arbitrary or ideologically motivated. The Order, summarized above, withdrew any guidance, instruction, recommendation, or document issued by the IWG.

As discussed above, the 2021 court order directed OSMRE to take a “hard look” at the costs of greenhouse gas emissions. In response, the draft and Final EIS included an SCC analysis that relied on guidance that has since been withdrawn because of logical deficiencies, a poor basis in empirical science, politicization, and the absence of a foundation in legislation. While the analysis is included in the Final EIS, in reaching the decision in this ROD, OSMRE gave the SCC analysis in the Final EIS the appropriate consideration based on its analytical flaws that were identified in EO 14154 and selected Alternative 1.

3.5.3.3 Ending Illegal Discrimination and Restoring Merit-Based Opportunity

EO 14154 and Presidential Memorandum (*Ending Illegal Discrimination and Restoring Merit-Based Opportunity*), require DOI to strictly adhere to NEPA, 42 U.S.C. §§ 4321 *et seq.* The Final EIS includes a discussion on environmental justice. However, because such Order and Memorandum repeal EO 12898 (Feb. 11, 1994) and 14096 (Apr. 21, 2023), evaluation of environmental justice is not legally required or necessary to make a reasoned decision. To reach its recommendation decision, OSMRE considered only the applicable statutory and regulatory requirements necessary for approval of the mining plan modification.

Finding

OSMRE finds that the selection of Alternative 1 was made in consideration of and is consistent with EO 14154 and the Presidential Memorandum Ending Illegal Discrimination and Restoring Merit-Based Opportunity.

3.5.4 National Environmental Policy Act of 1969

NEPA declares a national environmental policy and promotes consideration of environmental concerns by Federal agencies in decision making. DOI NEPA regulations are promulgated at 43 C.F.R. part 46. The OSMRE NEPA Handbook also provided guidance for the Final EIS.

Finding

OSMRE finds that the Final EIS complies with the procedural and analytical requirements of NEPA, including the Department's regulations and procedures implementing NEPA at 43 C.F.R. part 46 and Part 516 of the Departmental Manual. OSMRE's selection of Alternative 1 is consistent with 42 U.S.C. § 4332(2)(B) because OSMRE has insured "that presently unquantified environmental amenities and values [were] given appropriate consideration in decisionmaking along with economic and technical considerations."

3.5.5 Mineral Leasing Act of 1920

The BLM's authority to manage the public's coal resources comes from two laws: the Mineral Leasing Act of 1920, as amended, and the Mineral Leasing Act of 1947, as amended. These Acts provide for the leasing of minerals from public lands, including coal, and require that a royalty be paid on amounts mined and sold. The BLM's role is to conduct lease sales to ensure the public receives fair market value; and to administer and ensure compliance with the terms and conditions of those leases. The BLM also monitors production to ensure maximum economic recovery of the public's coal resource and verifies that production for royalty collection by the Office of Natural Resources Revenue.

Before conducting any Federal coal development or mining operations on Federal leases or licenses, the operator/lessee must submit and obtain approval of a resource

recovery and protection plan (R2P2). On April 16, 2019, the BLM received an R2P2 for the SCM, which included Federal coal leases MTM 094378 and MTM 110693. Following review, the BLM found the application to be complete and in conformance with the requirements of the Mineral Leasing Act of 1920, as amended, and the applicable regulations at 43 CFR part 3480, and approved the R2P2, effective October 1, 2019.

Finding

BLM's competitive lease sale and associated 2006 LBA EA, and its review and approval of the R2P2 constituted compliance with the Mineral Leasing Act. In addition, the Mineral Leasing Act of 1920, as amended, also requires an approved mining plan before a significant disturbance of the environment may occur. 30 U.S.C. § 207(c). OSMRE's recommendation of Alternative 1 of this mining plan modification, if approved by the ASLM, will be consistent with the R2P2 and will complete compliance with the Mineral Leasing Act, as amended.

3.5.6 Surface Mining Control and Reclamation Act of 1977

Before the commencement of any coal development or mining operations on a Federal lease or license, a permit application package (PAP) containing, among other documents, a R2P2 and a permit application must be submitted to the regulatory authority responsible for issuing SMCRA permits.

SMCRA establishes a program of cooperative Federalism that allows a state or tribe to enact and administer its own SMCRA regulatory program on non-Federal and non-Indian lands within its borders and subject to limits established by Federal minimum standards and with prescribed oversight and enforcement authority by OSMRE (30 U.S.C. § 1253). The Montana permanent program was approved by the Secretary in 1982. 30 C.F.R. § 926.10. MDEQ administers both SMCRA, the Montana Strip and Underground Mine Reclamation Act (MSUMRA), and the Montana Environmental Policy Act (MEPA). In addition, DOI and Montana entered into a State-Federal Cooperative Agreement in 1998 that allows Montana to be the primary SMCRA regulatory authority on Federal lands within Montana.

On January 23, 2008, Spring Creek Coal, LLC, submitted a PAP to MDEQ to revise SMP C1979012 to add the Federal coal within the LBA1 tracts. MDEQ found the PAP to

be administratively complete in August 2009 and determined that an EIS under MEPA was not necessary. A PAP notice was published in the local newspaper for four consecutive weeks followed by a 30-day public comment period. No comments were received.

In May 2011, MDEQ completed a checklist EA pursuant to the MEPA to assess potential environmental impacts of the PAP. The MDEQ published the EA and a Determination of Acceptability, followed by a public notice period. No comments were received. MDEQ approved the permit revision on June 21, 2011.

Finding

OSMRE finds that MDEQ's review and approval of the permit revision, which covers all of Alternative 1, constitutes compliance with SMCRA.

3.5.7 National Historic Preservation Act of 1966

Section 106 of the National Historic Preservation Act (NHPA) and its implementing regulations under 36 C.F.R. part 800 require all Federal agencies to consider the effects of Federal actions on cultural resources eligible for or listed in the National Register of Historic Places (NRHP). Traditional cultural properties are also protected under Section 106 of the NHPA.

In 2001, OSMRE, MDEQ, the SCM operator, and the Montana State Historic Preservation Officer (SHPO) executed a Memorandum of Agreement (MOA) pursuant to the NHPA as an enforceable condition under the SCM permit. Comprehensive investigations (BLM Class III inventory) of cultural resources within the SCM permit area are completed. As of 2018, 11 cultural sites within the SCM permit area were designated as eligible for listing on the NRHP, two of which are within the LBA1 tracts.

Site 24BH404 is the most culturally significant site within the LBA1 tracts. The site consists of 46 panels of petroglyphs, including modern, historic and prehistoric glyphs. However, the Federal coal under site 24BH404 was removed from the lease, eliminating any potential disturbance to the site, and, in 2015, mitigation was completed for the purpose of recording the site for historical record. The site was photographed with 3D imagery so that it can be recreated if the site is damaged by weather. The remaining historic properties within the SCM permit were mitigated

pursuant to the MOA. The MOA remains in place to guide mitigation if incidental cultural discoveries are encountered during mining.

Finding

OSMRE finds that the Section 106 process is complete, and Alternative 1 will not negatively impact any culturally significant sites and the MOA will adequately mitigate impacts to any unanticipated cultural discoveries during mining operations.

3.5.8 Tribal Consultation

Native American tribes were consulted during the preparation of the 2006 and 2016 LBA1 EAs. In response to the 2006 LBA EA consultation, response letters were received from the Blackfeet, Cheyenne River Sioux, and the Northern Cheyenne Tribes. The Blackfeet and Cheyenne River Sioux did not have specific concerns about the LBA1 tracts. The Northern Cheyenne Historic Preservation Officer requested additional information and participated in a discussion of the cultural resource issues related to the LBA1 tracts and accompanied mine personnel on tour of several of the sites on February 14, 2006. The Northern Cheyenne Historic Preservation Officer conducted tribal cultural surveys to determine whether there were any indicators that might suggest cultural tribal properties exist within the LBA1 tracts.

While preparing the 2016 LBA1 EA, OSMRE requested continued consultation with affected tribes for the stages of the proposal development and implementation of the final federal action. On May 23, 2016, the Cheyenne and Arapahoe Tribes provided a letter in response to OSMRE's consultation request, confirming no properties would be affected. No other tribes responded to OSMRE's consultation request.

While preparing the EIS, OSMRE sent letters to 23 tribes during public scoping and again for the Notice of Availability of the draft EIS. No tribes responded to OSMRE's consultation requests.

Finding

OSMRE finds it has made a good faith and reasonable effort to invite any tribes that may be affected by the Proposed Action to consult on OSMRE's decision and that it has satisfied all tribal consultation obligations when selecting Alternative 1.

3.5.9 Endangered Species Act of 1973

Section 7(a)(2) of the Endangered Species Act (ESA) requires each Federal agency to ensure that its activities are not likely to jeopardize the continued existence of listed species or adversely modify designated critical habitats.

While preparing the EIS, in August 2024, OSMRE requested an official species list using the U.S. Fish and Wildlife Service (USFWS) Information Planning and Consultation System (IPaC) of protected species that may be affected by the Proposed Action. At that time, there were no listed or proposed species or designated critical habitats. As such, OSMRE determined that the proposed action would have no effect on any listed or proposed species or designated critical habitats. A “no effect” determination does not require Section 7 consultation with USFWS.

In January 2025, while preparing the MPDD after publication of the Final EIS, OSMRE submitted a request for an updated official species list through IPaC. The updated official species list included three newly proposed species: the proposed threatened monarch butterfly (*Danaus Plexippus*) and western regal fritillary (*Argynnis idalia occidentalis*), and the proposed endangered Suckley’s cuckoo bumble bee (*Bombus suckleyi*). No designated critical habitat for these species has been proposed in the vicinity of the SCM.

On February 11, 2025, after informal discussion with the USFWS Montana Ecological Field Office, OSMRE submitted to USFWS its determinations that the proposed mining plan modification would “not jeopardize the continued existence” of the monarch butterfly, the western regal fritillary, or the Suckley’s cuckoo bumble bee species. OSMRE’s “no jeopardy” determinations were made based on the absence of suitable habitat within the proposed project area, based on previous habitat surveys. Additionally, if approved, the Alternative 1 would adhere to SCM’s approved Reclamation Plan in SMP C1979012, which requires that reclamation efforts, including but not limited to backfilling, grading, topsoil replacement, and revegetation, on all land that is disturbed by surface mining activities will occur as contemporaneously as practicable. Revegetation is required to be comprised of species native to the area, or of introduced species where desirable and necessary to achieve the approved

postmining land use and approved by MDEQ (30 C.F.R. § 816.111). The SCM will adhere to the vegetation monitoring described in Section 1(h)(ix) of the approved Reclamation Plan. On February 21, 2025, USFWS concurred with OSMRE's determinations that the proposed action would not jeopardize the continued existence of the three proposed species.

Finding

OSMRE finds that the selection of Alternative 1 complies with the ESA based on the analysis outlined above. OSMRE's determination and USFWS's concurrence that the proposed action would have no effect on any listed species or designated critical habitats and would not jeopardize the continued existence of any proposed species satisfies OSMRE's obligations under the ESA.

3.5.10 Clean Air Act of 1970

The State of Montana administers the Federal Clean Air Act and the Montana Clean Air Act. Montana Air Quality Permits (MAQP) are issued by the MDEQ. The SCM's current MAQP #1120-12 limits the SCM to producing a maximum of 30 Mt of coal per year to ensure that all potential sources of air pollutants from mining operations comply with the Montana Clean Air Act.

Finding

OSMRE finds that Alternative 1 is within the production rate limitations of the SCM's current air quality permit and complies with the Clean Air Act.

3.5.11 Clean Water Act 1972

MDEQ is responsible for administering the Federal Clean Water Act and the Montana Water Quality Act, which prevents degradation of surface and groundwater due to discharges of mine wastewater and storm water. The Montana Pollutant Discharge Elimination System (MPDES) permit is required for surface water and storm water discharges, while the Montana Ground Water Pollution Control System (MCWPCS) permit is required for ground water discharge.

Mining operations in Montana must be designed and conducted in a way to prevent material damage, with respect to protection of the hydrologic balance,

degradation or reduction by coal mining and reclamation operations of the quality or quantity of water outside of the mine permit area in a manner or to an extent that land uses or beneficial uses of water are adversely affected, water quality standards are violated, or water rights are impacted. The SCM MPDES permit (Permit MT0024619) and stormwater permit (Permit MTR000514) have no changes associated with the proposed mining plan modification.

The Final EIS analyzes the direct, indirect, and cumulative impacts to surface and groundwater resources from the proposed mining plan modification (**Sections 4.5.1, 4.5.2, 5.2.4.1, and 5.2.4.2**).

Finding

OSMRE finds that Alternative 1, under SCM's current water quality permits, complies with the Clean Water Act.

4.0 APPROVAL

In consideration of the information presented above, I approve this OSMRE ROD and the selection of Alternative 1 (Proposed Action), as described in Section 3.2 of this ROD. The State of Montana has approved the MSUMRA permit, which sets forth requirements to minimize environmental impacts that could potentially occur as a result of the Proposed Action. Accordingly, I recommend approval without conditions of the mining plan modification to the ASLM consistent with Alternative 1. This action can be implemented following approval of the mining plan modification by the ASLM.

This ROD is effective on signature.

David A. Berry, Regional Director, Regions 5, 7, 8, 9, 10 and
11, Office of Surface Mining Reclamation and Enforcement

EXHIBIT C



Global Greenhouse Gas Overview

On This Page:

Global Emissions and Removals by Gas | Global Emissions by Economic Sector |
Trends in Global Emissions | Emissions by Country

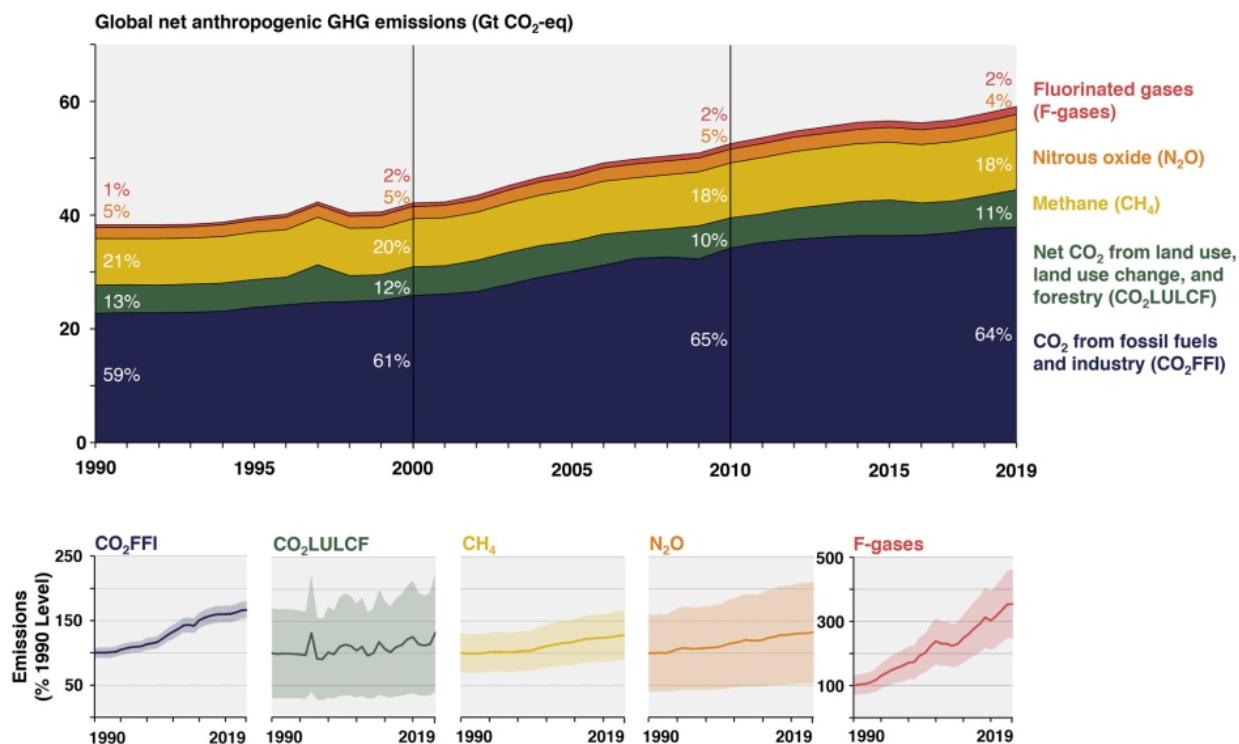
Global Emissions and Removals by Gas

At the global scale, the key greenhouse gases emitted by human activities are:

- **Carbon dioxide (CO₂)** <<https://epa.gov/ghgemissions/overview-greenhouse-gases#carbon-dioxide>>: Fossil fuel use is the primary source of CO₂. CO₂ can also be emitted from the landscape through deforestation, land clearance for agriculture or development, and degradation of soils. Likewise, land management can also remove additional CO₂ from the atmosphere through reforestation, improvement of soil health, and other activities.
- **Methane (CH₄)** <<https://epa.gov/ghgemissions/overview-greenhouse-gases#methane>>: Agricultural activities, waste management, energy production and use, and biomass burning all contribute to CH₄ emissions.
- **Nitrous oxide (N₂O)** <<https://epa.gov/ghgemissions/overview-greenhouse-gases#nitrous-oxide>>: Agricultural activities, such as fertilizer use, are the primary source of N₂O emissions. Chemical production and fossil fuel combustion also generates N₂O.
- **Fluorinated gases (F-gases)** <<https://epa.gov/ghgemissions/overview-greenhouse-gases#f-gases>>: Industrial processes, refrigeration, and the use of a variety of consumer products contribute to emissions of F-gases, which include hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF₆).

Additional compounds in the atmosphere including solid and liquid aerosol and other greenhouse gases, such as water vapor and ground-level ozone can also impact the climate. Learn more about these compounds and climate change on our

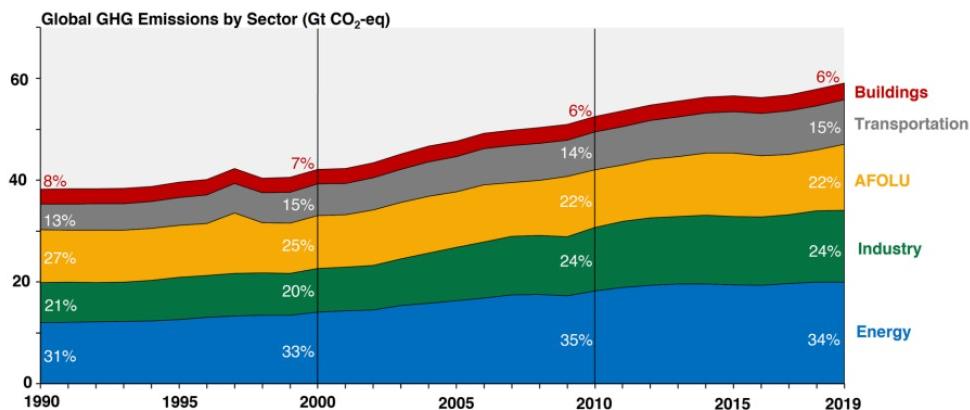
Basics of Climate Change page <<https://epa.gov/climatechange-science/basics-climate-change#othergases>>.



Source: Data from IPCC (2022); Based on global emissions from 2019, details on the sectors and individual contributing sources can be found in the *Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change, Mitigation of Climate Change, Chapter 2*.

Global Emissions by Economic Sector

Global greenhouse gas emissions can also be broken down by the economic activities that lead to their atmospheric release.^[1]

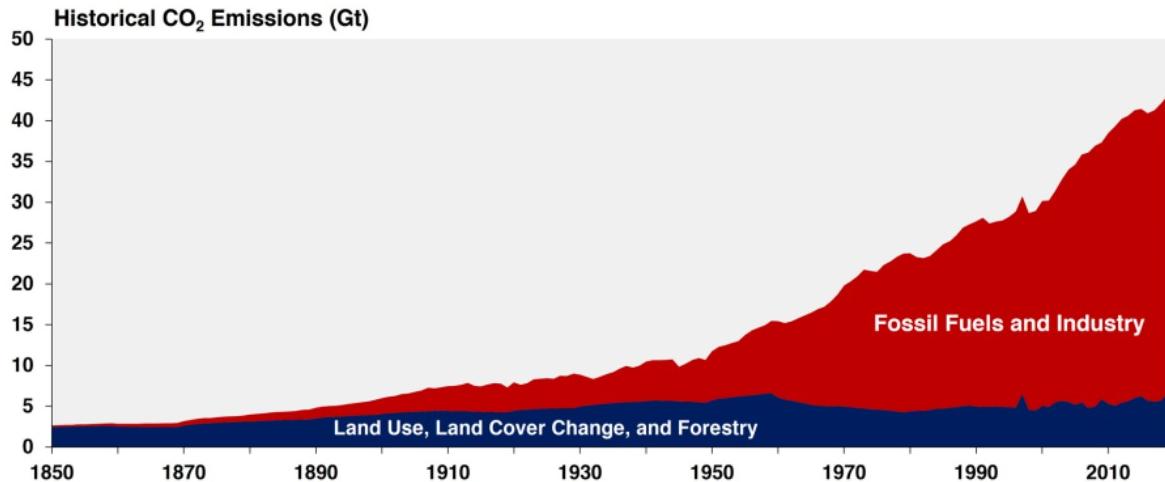


Source: Data from IPCC (2022); Based on global emissions from 2019, details on the sectors and individual contributing sources can be found in the *Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change, Mitigation of Climate Change, Chapter 2*.

- **Electricity and Heat Production** <<https://epa.gov/ghgemissions/sources-greenhouse-gas-emissions#electricity>> (34% of 2019 global greenhouse gas emissions): The burning of coal, natural gas, and oil for electricity and heat is the largest single source of global greenhouse gas emissions.
- **Industry** <<https://epa.gov/ghgemissions/sources-greenhouse-gas-emissions#industry>> (24% of 2019 global greenhouse gas emissions): Greenhouse gas emissions from industry primarily involve fossil fuels burned on site at facilities for energy. This sector also includes emissions from chemical, metallurgical, and mineral transformation processes not associated with energy consumption and emissions from waste management activities. (Note: Emissions from industrial electricity use are excluded and are instead covered in the Electricity and Heat Production sector.)
- **Agriculture, Forestry, and Other Land Use** <<https://epa.gov/ghgemissions/sources-greenhouse-gas-emissions#land-use-and-forestry>> (22% of 2019 global greenhouse gas emissions): Greenhouse gas emissions from this sector come mostly from agriculture <<https://epa.gov/ghgemissions/sources-greenhouse-gas-emissions#agriculture>> (cultivation of crops and livestock) and deforestation. This estimate does not include the CO₂ that ecosystems remove from the atmosphere by sequestering carbon (e.g. in biomass, soils).^[2]
- **Transportation** <<https://epa.gov/ghgemissions/sources-greenhouse-gas-emissions#transportation>> (15% of 2019 global greenhouse gas emissions): Greenhouse gas emissions from this sector primarily involve fossil fuels burned for road, rail, air, and marine transportation. Almost all (95%) of the world's transportation energy comes from petroleum-based fuels, largely gasoline and diesel.^[3]
- **Buildings** <<https://epa.gov/ghgemissions/sources-greenhouse-gas-emissions#commercial-and-residential>> (6% of 2019 global greenhouse gas emissions): Greenhouse gas emissions from this sector arise from onsite energy generation and burning fuels for heat in buildings or cooking in homes. Note: Emissions from this sector are 16% when electricity use in buildings is included in this sector instead of the Energy sector.

Note on emissions sector categories.

Trends in Global Emissions



Source: Data from IPCC (2022); Based on global emissions from 2019, details on the sectors and individual contributing sources can be found in the *Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change, Mitigation of Climate Change, Chapter 2*.

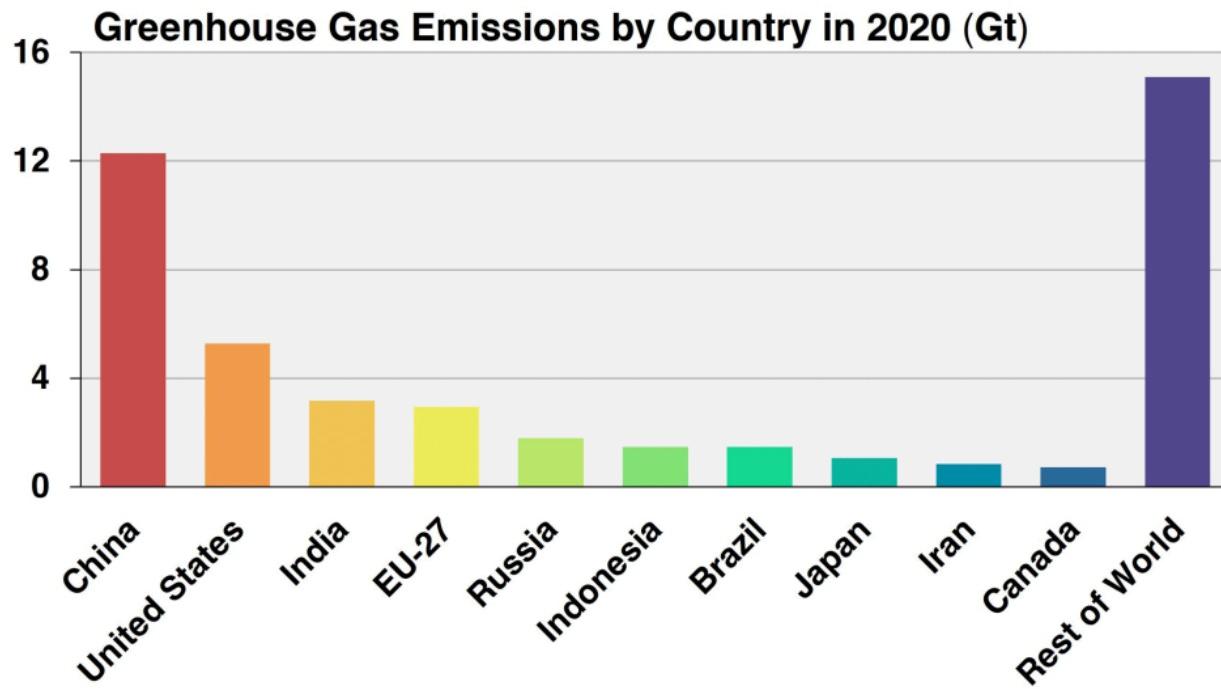
Global CO₂ emissions from all sectors have significantly increased since 1850. The majority of this increase has resulted from increased fossil fuel consumption and industrial emissions. Agriculture, deforestation, and other land-use changes have been the second-largest contributors.^[1]

Emissions of non-CO₂ greenhouse gases (CH₄, N₂O, and F-gases) have also increased significantly since 1850.

- Globally, greenhouse gas emissions continued to rise across all sectors and subsectors, most rapidly in the transport and industry sectors.
- While the trend in emissions continues to rise, annual greenhouse gas growth by sector slowed in 2010 to 2019, compared to 2000 to 2009, for energy and industry, however remained roughly stable for transport.
- The trend for AFOLU remains more uncertain, due to the multitude of drivers that affect emissions and removals for land use, land-use change and forestry.
- Greenhouse gas emissions from industry, buildings and transport sectors are driven by
 - rising demand for construction materials and manufactured products,
 - increasing floor space per capita,
 - increasing building energy use,
 - travel distances, and vehicle size and weight.

To learn more about past and projected global emissions of non-CO₂ gases, please see the EPA report, *Global Non-CO₂ Greenhouse Gas Emission Projections & Mitigation Potential: 2015-2050* <<https://epa.gov/global-mitigation-non-co2-greenhouse-gases/global-non-co2-greenhouse-gas-emission-projections>>. For further insights into mitigation strategies specifically within the U.S. forestry and agriculture sectors, refer to the latest Climate Economic Analysis report on Greenhouse Gas Mitigation Potential in U.S. Forestry and Agriculture <<https://epa.gov/climate-change/climate-economic-analysis>>.

Emissions by Country



Source: Data from Climate Watch; Climate Watch Historical GHG Emissions (1990-2020). 2023. Washington, DC: World Resources Institute. Available online at: https://www.climatewatchdata.org/ghg-emissions?end_year=2021&start_year=1990

In 2020, the top ten greenhouse gas emitters were China, the United States, India, the European Union, Russia, Indonesia, Brazil, Japan, Iran, and Canada. These data include CO₂, CH₄, N₂O, and fluorinated gas emissions from energy, agriculture, forestry and land use change, industry, and waste. Together, these top ten countries represent approximately 67% of total greenhouse gas emissions in 2020.

Emissions and sinks related to changes in land use are not included in these estimates. However, changes in land use can be important: estimates indicate that net global greenhouse gas emissions from agriculture, forestry, and other land use were approximately 12 billion metric tons of CO₂ equivalent,^[2] or about 21% of total global greenhouse gas emissions.^[3] In areas such as the United States <<https://epa.gov/ghgemissions/sources-greenhouse-gas-emissions#land-use-and-forestry>> and Europe, changes in land use associated with human activities have the net effect of absorbing CO₂, partially offsetting the emissions from deforestation in other regions.

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Related Links

EPA resources

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<<https://doi.org/10.1017/9781009157988.004>>. In: Climate Change and Land: an IPCC special report on climate change, desertification, land degradation, sustainable land management, food security, and greenhouse gas fluxes in terrestrial ecosystems [P.R. Shukla, J. Skea, E. Calvo Buendia, V. Masson-Delmotte, H.-O. Pörtner, D.C. Roberts, P. Zhai, R. Slade, S. Connors, R. van Diemen, M. Ferrat, E. Haughey, S. Luz, S. Neogi, M. Pathak, J. Petzold, J. Portugal Pereira, P. Vyas, E. Huntley, K. Kissick, M. Belkacemi, J. Malley, (eds.)].
<https://doi.org/10.1017/9781009157988.004>

3. U.S. Energy Information Administration, Annual Energy Outlook 2021 ↗ <https://www.eia.gov/outlooks/ieo/data/pdf/refl01_r.pdf>, (February 2021), www.eia.gov/aoe

- Overview of Greenhouse Gases
<<https://epa.gov/ghgemissions/overview-greenhouse-gases>>
- Sources of Greenhouse Gas Emissions (in the United States)
<<https://epa.gov/ghgemissions/sources-greenhouse-gas-emissions>>
- Non-CO₂ Greenhouse Gases: Emissions and Trends
<<https://cfpub.epa.gov/ghgdata/nonco2>>
- Capacity Building for National GHG Inventories
<<https://epa.gov/ghgemissions/capacity-building-paris-agreement-reporting>>

Other resources

- UNFCCC GHG Data Interface ↗
<<https://unfccc.int/topics/mitigation/resources/registry-and-data/ghg-data-from-unfccc>>
- PRIMAP ↗
<<https://primap.org/primap-hist/>>
- European Commission Emission Database for Global Atmospheric Research ↗
<<https://edgar.jrc.ec.europa.eu/>>
- World Development Indicators ↗
<<https://datatopics.worldbank.org/world-development-indicators/>>
- Climate Watch ↗
<<https://www.climatewatchdata.org/>>

- Carbon Dioxide and Information Analysis Center (CDIAC) [🔗](https://data.electricpower.us/portsals/cdiac)
<<https://data.electricpower.us/portsals/cdiac>>
- Greenhouse Gas Emissions from Energy Data Explorer (IEA) [🔗](https://www.iea.org/data-and-statistics/data-tools/greenhouse-gas-emissions-from-energy-data-explorer)
<<https://www.iea.org/data-and-statistics/data-tools/greenhouse-gas-emissions-from-energy-data-explorer>>

Last updated on March 31, 2025

EXHIBIT D



U.S. DEPARTMENT
of ENERGY



Resource Adequacy Report

Evaluating the Reliability and Security of the United States Electric Grid

July 2025

Acknowledgments

This report and associated analysis were prepared for DOE purposes to evaluate both the current state of resource adequacy as well as future pressures resulting from the combination of announced retirements and large load growth.

It was developed in collaboration with and with assistance from the Pacific Northwest National Laboratory (PNNL) and National Renewable Energy Laboratory (NREL). We thank the North American Electric Reliability Corporation (NERC) for providing data used in this study, the Telos Corporation for their assistance in interpreting this data, and the U.S Energy Information Administration (EIA) for their dissemination of historical datasets. In addition, thank you to NREL for providing synthetic weather data created by Evolved Energy Research for the Regional Energy Deployment System (ReEDS) model.

DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience.

Historically, the nation's power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued. Thus, one of the key takeaways from this study process is the underscored "call to action" for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security.

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List of Acronyms

AI	Artificial Intelligence
CAISO	California Independent System Operator
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EO	Executive Order
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
GADS	Generating Availability Data System
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ITCS	Interregional Transfer Capability Study
LBNL	Lawrence Berkeley National Laboratory
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LTRA	Long-Term Reliability Assessment
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PJM	PJM Interconnection, LLC
PNNL	Pacific Northwest National Laboratory
ReEDS	Regional Energy Deployment System
RTO	Regional Transmission Organization
SERC	SERC Reliability Corporation
TPR	Transmission Planning Region
USE	Unserved Energy

Background to this Report

On April 8, 2025, President Trump issued Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid." EO 14262 builds on EO 14156, "Declaring a National Emergency (Jan. 20, 2025)," which declared that the previous administration had driven the Nation into a national energy emergency where a precariously inadequate and intermittent energy supply and increasingly unreliable grid require swift action. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation's electrical grid.

EO 14262 mandates the development of a uniform methodology for analyzing current and anticipated reserve margins across regions of the bulk power system regulated by the Federal Energy Regulatory Commission (FERC). Among other things, EO 14262 requires that such methodology accredit generation resources based on the historical performance of each generation resource type. This report serves as DOE's response to Section 3(b) of EO 14262 by delivering the required uniform methodology to identify at-risk region(s) and guide reliability interventions. The methodology described herein and any analysis it produces will be assessed on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States.

Executive Summary

Our Nation possesses abundant energy resources and capabilities such as oil and gas, coal, and nuclear. The current administration has made great strides—such as deregulation, permitting reform, and other measures—to enable addition of more energy infrastructure crucial to the utilization of these resources. However, even with these foundational strengths, the accelerated retirement of existing generation capacity and the insufficient pace of firm, dispatchable generation additions (partly due to a recent focus on intermittent rather than dispatchable sources of energy) undermine this energy outlook.

Absent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation. A failure to power the data centers needed to win the AI arms race or to build the grid infrastructure that ensures our energy independence could result in adversary nations shaping digital norms and controlling digital infrastructure, thereby jeopardizing U.S. economic and national security.

Despite current advancements in the U.S. energy mix, this analysis underscores the urgent necessity of robust and rapid reforms. Such reforms are crucial to powering enough data centers while safeguarding grid reliability and a low cost of living for all Americans.

Key Takeaways

- **Status Quo is Unsustainable.** The status quo of more generation retirements and less dependable replacement generation is neither consistent with winning the AI race and ensuring affordable energy for all Americans, nor with continued grid reliability (ensuring “resource adequacy”). Absent intervention, it is impossible for the nation’s bulk power system to meet the AI growth requirements while maintaining a reliable power grid and keeping energy costs low for our citizens.
- **Grid Growth Must Match Pace of AI Innovation.** The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. The situation necessitates a radical change to unleash the transformative potential of innovation.
- **Retirements Plus Load Growth Increase Risk of Power Outages by 100x in 2030.** The retirement of firm power capacity is exacerbating the resource adequacy problem. 104 GW of firm capacity are set for retirement by 2030. This capacity is not being replaced on a one-to-one basis and losing this generation could lead to significant outages when weather conditions do not accommodate wind and solar generation. In the “plant closures” scenario of this analysis, annual loss of load hours (LOLH) increased by a factor of a hundred.
- **Planned Supply Falls Short, Reliability is at Risk.** The 104 GW of retirements are projected to be replaced by 209 GW of new generation by 2030; however, only 22 GW would come from firm baseload generation sources. Even assuming no retirements, the model found increased risk of outages in 2030 by a factor of 34.

- **Old Tools Won't Solve New Problems.** Antiquated approaches to evaluating resource adequacy do not sufficiently account for the realities of planning and operating modern power grids. At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude, and duration of power outages; move beyond exclusively analyzing peak load time periods; and develop integrated models to enable proper analysis of increasing reliance on neighboring grids.

This report clearly demonstrates the need for rapid and robust reform to address resource adequacy issues across the Nation. Inadequate resource adequacy will hinder the development of new manufacturing in America, slow the re-industrialization of the U.S. economy, drive up the cost of living for all Americans, and eliminate the potential to sustain enough data centers to win the AI arms race.

Developing a Uniform Methodology

DOE's resource adequacy methodology assesses the U.S. electric grid's ability to meet future demand through 2030. It provides a forward-looking snapshot of resource adequacy that is tied to electricity supply and new load growth, systematically exploring a range of dimensions that can be compared across regions. As detailed in the methodology section of this report, the model is derived from the North American Electric Reliability Corporation (NERC) Interregional Transfer Capability Study (ITCS) which leverages time-correlated generation and outages based on actual historic data.¹ A deterministic approach² simulates system stress in all hours of the year and incorporates varied grid conditions and operating scenarios based on historical events:

- **Demand for Electricity – Assumed Load Growth:** The methodology accounts for the significant impact of data centers, particularly those supporting AI workloads, on electricity demand. Various organizations' projections for incremental data center electricity use by 2030 range widely (35 GW to 108 GW). DOE adopted a national midpoint assumption of 50 GW by 2030, aligning with central projections from Electric Power Research Institute (EPRI)³ and Lawrence Berkeley National Laboratory (LBNL).⁴ This 50 GW was allocated regionally using state-level growth ratios from S&P's forecast,⁵ reflecting infrastructure characteristics, siting trends, and market activity; and, mapped to NERC Transmission Planning Regions (TPRs).

1. This model differs from traditional peak hour reliability assessments in that it explicitly simulates grid performance hour-by-hour across multiple weather years with finer geographic detail and optimized inter-regional transfers, and explores various retirement and build-out scenarios. Furthermore, the DOE approach integrates weather-synchronized outage data.

2. Deterministic approaches evaluate resource adequacy using relatively stable or fixed assumptions about the representation of the power system. Probabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty that require more computing power. Deterministic was chosen for this analysis for transparency and to model detailed historic system conditions.

3. EPRI, "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption," March 2024, <https://www.epri.com/research/products/3002028905>.

4. Shehabi, A., et al., "2024 United States Data Center Energy Usage Report," <https://escholarship.org/uc/item/32d6m0d1>.

5. S&P Global – Market Intelligence, "US Datacenters and Energy Report," 2024.

An additional 51 GW of non-data center load was modeled using NERC data, historical loads (2019-2023), and simulated weather years (2007-2013), adjusted by the Energy Information Administration's (EIA) 2022 energy forecast, with interpolation between 2024 and 2033 to estimate 2030 demand.

- **Supply of Electricity – Assumed Generation Retirements and Additions:** Between the current system and the projected 2030 system, the model considers three scenarios for generator retirements and additions. These scenarios were selected to describe the metrics of interest and how they change during certain assumptions of generation growth and retirements.

The resource adequacy standard (or criterion) is the measure that defines the desired level of adequacy needed for a given system. Conceptually, a resource adequacy criterion has two components—metrics and target levels—that determine whether a system is considered adequate. Comprehensive resource adequacy metrics⁶ are incorporated in this analysis to capture the magnitude and duration of system stress events:

- **Magnitude of Outages – Normalized Unserved Energy (NUSE):** Measures the amount of unmet electrical energy demand because of insufficient generation or transmission, typically measured in megawatt hours (MWh).

While USE describes the absolute amount of energy not delivered, it is less useful when comparing systems of different size or across different periods. Normalizing, by dividing by total load over a whole period (for example, a year) allows comparison of these metrics across different system sizes, demand levels, and periods of analysis. For example, 100 MWh of USE in a small, isolated microgrid can be more impactful than 100 MWh of USE in a larger regional grid that serves millions of people. USE is normalized by dividing by total load:

$$\frac{100 \text{ MWh (of unserved energy)}}{10,000,000 \text{ MWh (of total energy delivered in a year)}} \times 100 = 0.001 \text{ percent}$$

Although the use of NUSE is not standardized in the U.S. today,⁷ several system operators domestically and across the world have begun using NUSE as a useful metric.

- **Duration of Outages – Loss of Load Hours (LOLH):** Measures the expected duration of power outages when a system's load exceeds its available generation capacity. At the core, LOLH helps assess how frequently and for how long the power system is likely to experience insufficient supply, providing a picture of reliability in terms of time. LOLH is calculated as both a total and average value per year, in addition to the maximum percentage of load lost in any given hour per year.

6. In the interest of technical accuracy, and separate from their contextualization in the main text, NUSE is more precisely a measure of volume that is expressed as a percentage. Similarly, 2.4 hours of LOLH represents the cumulative sum of distinct periods of load loss, not a singular, continuous duration.

7. There is no common planning criterion for this metric in North America. NERC's Long-Term Reliability Assessment employs a normalized expected unserved energy (NEUE) metric to define target risk levels for each region. Grid operators, such as ISO-NE, have also considered NUSE in energy adequacy studies. For example, see ISO-NE, "Regional Energy Shortfall Threshold (REST): ISO's Current Thinking Regarding Tail Selection," April 2025, https://www.iso-ne.com/static-assets/documents/100022/a09_rest_april_2025.pdf.

Reliability Standard

DOE's methodology recognizes that the traditional 1-in-10 loss of load expectation (LOLE) criterion is insufficient for a complete assessment of resource adequacy and risk profile. This antiquated criterion is not calculated uniformly and fails to adequately account for crucial factors such as the duration and magnitude of potential outages.⁸ To provide a comprehensive understanding of system reliability and, specifically, to complement current resource adequacy standards while informing the creation of new criteria, the methodology uses the following reliability standard:

- **Duration of Outages:** No more than 2.4 hours of lost load in an individual year.⁹ This translates into one day of lost load in ten years to meet the 1-in-10 criteria.
- **Magnitude of Outages:** No more than an NUSE of 0.002%.¹⁰ This means that the total amount of energy that cannot be supplied to customers is 0.002% of the total energy demanded in a given year.

Achieving Reliability Standard

- **Perfect Capacity Surplus/Deficit:** Defined as the amount of generation capacity (in MW) a region would need to achieve specified threshold conditions. Based on these thresholds, this standard helps answer the hypothetical question of how much more (or less) power plant capacity is needed for a power system to be considered "perfectly reliable" according to pre-defined standards. This methodology employs this perfect capacity metric to identify the amount of capacity needed to remedy potential shortfalls (or excesses) in generation.

Key Results Summary

This analysis developed three separate cases for 2030. The "**Plant Closures**" case assumes all announced retirements occur plus mature generation additions based on NERC's Tier 1 resources category,¹¹ which encompasses completed and under-construction power generation projects, as well as those with firm-signed and approved interconnection service or power purchase agreements. The "**No Plant Closures**" case assumes no retirements plus mature additions. A "**Required Build**" case further compares the impacts of retirements on perfect capacity additions needed to return 2030 to the current system level of reliability.

8. While 1-in-10 analyses have evolved, industry experts have raised concerns about its effectiveness to address future system risks. Concerns include energy constraints that arise from intermittent resources, increasing battery storage, limited fuel supplies, and the shifting away of peak load periods from times of supply shortfalls.

9. The "1-in-10 year" reliability standard for electricity grids means that, on average, there should be no more than one day (24 hours) of lost load over a ten-year period. This translates to a maximum of 2.4 hours of lost load per year.

10. This analysis targets NUSE below 0.002% for each region because this is the target NERC uses to represent high risk in resource adequacy analyses. Estimates used in industry and analyzed recently range from 0.0001% to 0.003%.

10. Mature generation additions are based on NERC's 2024 LTRA Tier 1 resources, which assume that only projects considered very mature in the development pipeline will be built. For example, Tier 1 additions are those with signed interconnection agreements or power purchase agreements, or included in an integrated resource plan, indicating a high degree of certainty in their addition to the grid. Full details of the retirement and addition assumptions can be found in the methodology section of this report.

DOE ran simulations using 12 different years of historical weather. Every hour was based on actual data for wind, solar, load, and thermal availability to stress test the grid under a range of realistic weather conditions. The benefit of this approach is that it allows for transparent review of how actual conditions manifest themselves in capacity shortfalls. For all scenarios, LOLH and NUSE are calculated and used to compare how they change based on generation growth, retirements, and potential weather conditions.

- **Current System:** Supply of power (generation) and demand for power (load) consistent with 2024 NERC Long-Term Reliability Assessment (LTRA), including 2023 actual generation plus Tier 1 additions for 2024.
- **Plant Closures:** This case assumes 104 GW of announced retirements based on NERC estimates including approximately 71 GW of coal and 25 GW of natural gas, which closely align with retirement numbers in EIA's 2025 Annual Energy Outlook. In addition, this case assumes 100% of 2024 NERC LTRA Tier 1 additions totaling 209 GW are constructed by 2030. This includes 20 GW of new natural gas, 31 GW of additional 4-hour batteries, 124 GW of new solar and 32 GW of incremental wind. Details of the breakdown can be found in Appendix A.
- **No Plant Closures:** This case adds all the Tier 1 NERC additions but assumes no retirements.
- **Required Build:** To understand how much capacity may need to be added to reach reliability targets, the analysis adds hypothetical perfect capacity (which is idealized capacity that has no outages or profile) until a NUSE target of 0.002% is realized in each region. This scenario includes the same assumptions about retirements as our Plant Closures scenario described above.

As shown in the figures and tables below, the model shows a significant decline in all reliability metrics between the current system scenario and the 2030 Plant Closures scenario. Most notably, there is a hundredfold increase in annual LOLH from 8.1 hours per year in the current case to 817 hours per year in the 2030 Plant Closures. In the worst weather year assessed, the total lost load hours increase from 50 hours to 1,316 hours.

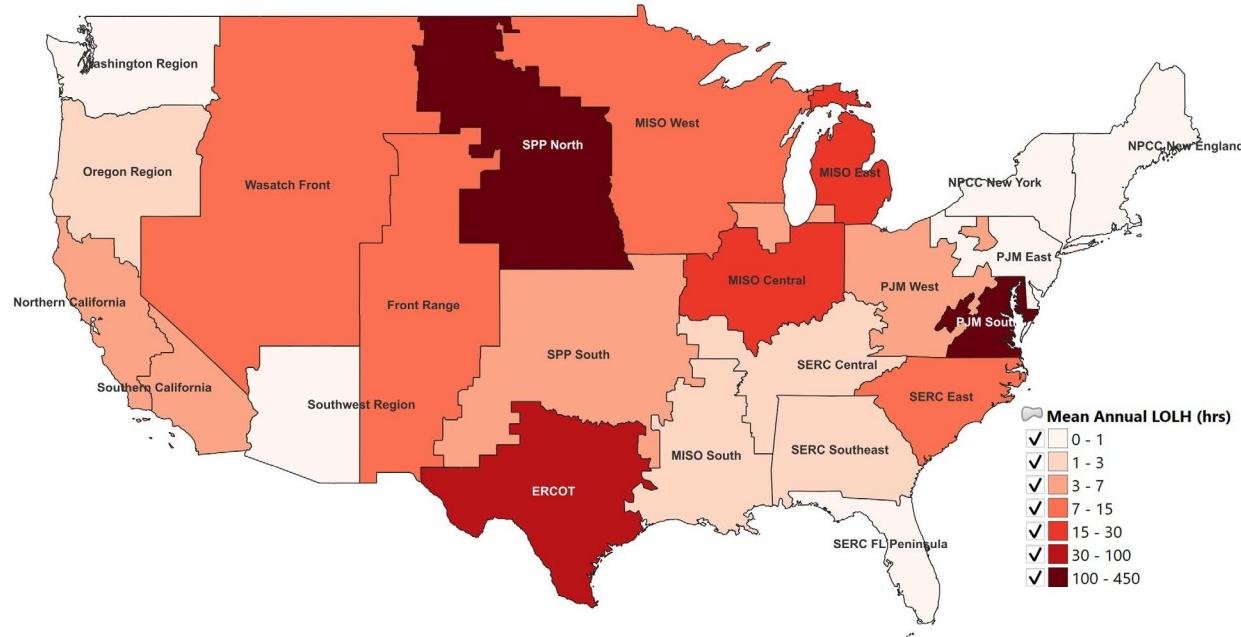


Figure 1. Mean Annual LOLH by Region (2030) – Plant Closures

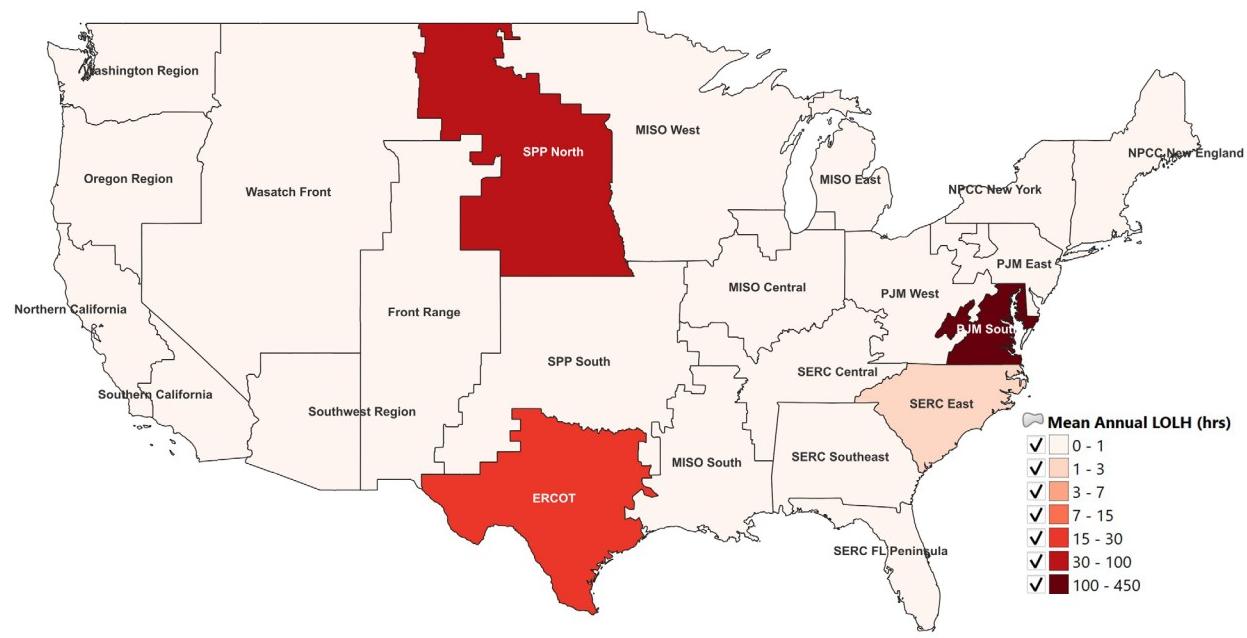


Figure 2. Mean Annual LOLH by Region (2030) – No Plant Closures

Table 1. Summary Metrics Across Cases

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	8.1	817.7	269.9	13.3
Normalized Unserved Energy (%)	0.0005	0.0465	0.0164	0.00048
WORST WEATHER YEAR				
Annual Loss of Load Hours	50	1316	658	53
Normalized Unserved Load (%)	0.0033	0.1119	0.0552	0.002

Current System Analysis

Analysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE. This indicates relative reliability for most regions based on the average indicators of risk used in this study. In the current system case, ERCOT would be expected to experience on average 3.8 LOLH annually going forward and a NUSE of 0.0032%. When looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour.

However, PJM, ERCOT,¹² and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load. This results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load. It is worth noting that in the case of PJM and SPP, the current system model shortfalls occurred within subregions rather than for the entire ISO footprint.

12. ERCOT has since winterized its generation fleet and did not suffer any outages during Winter Storm Elliot.

2030 Model Results

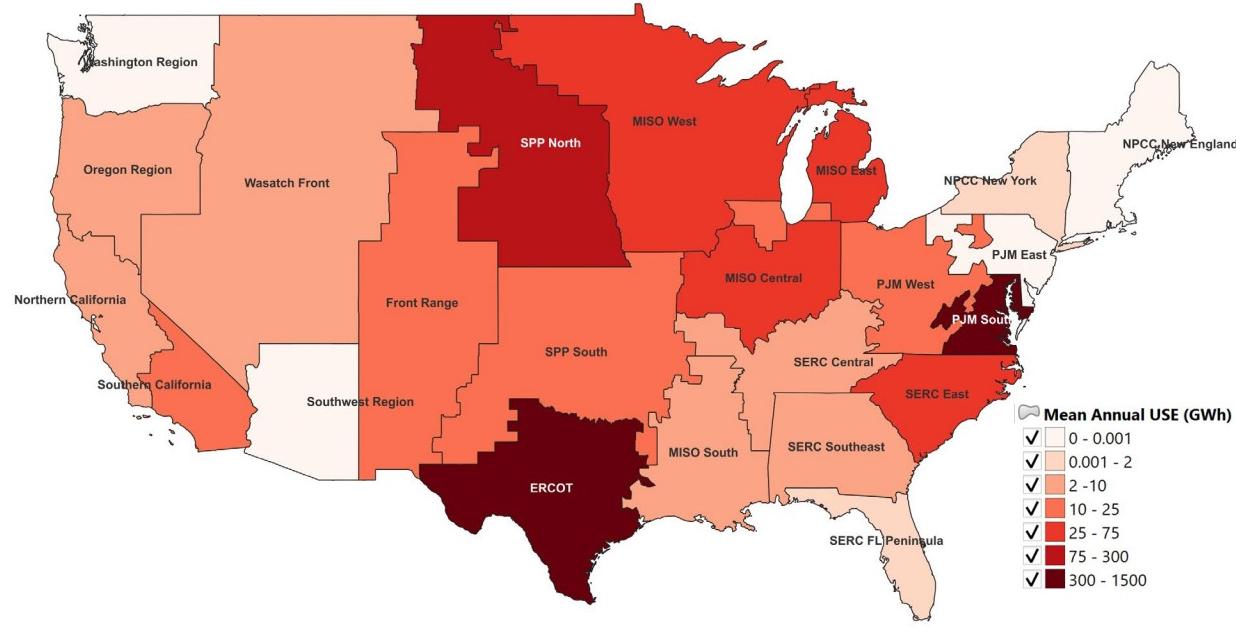


Figure 3. Mean Annual NUSE by Region (2030) -Plant Closures

Key Findings – Plant Closures Case:

- **Systemwide Failures:** All regions except ISO-NE and NYISO failed reliability thresholds. These two regions did not have additional AI/data center (AI/DC) load growth modeled.
- **Loss of Load Hours (LOLH):** Ranged from 7 hours/year in CAISO to 430 hours/year in PJM.
- **Load Shortfall Severity:** Max shortfall reached as high as 43% of hourly load in PJM; 31% in CAISO.
- **Normalized Unserved Energy:** Normalized values ranged from 0.0032% (non-CAISO West) to 0.1473% (PJM), far exceeding thresholds of 0.002%.
- **Extreme Events:** Most regions experienced ≥3 hours of unserved load in at least one year. PJM had 1,052 hours in its worst year.
- **Spatial Takeaways:** Subregions in PJM, MISO, and SERC met thresholds—indicating possible benefits from transmission—but SPP and CAISO failed in all subregions.

Key Findings – No Plant Closures Case:

- **Improved System Performance:** Most regions avoided loss of load events. PJM, SPP, and SERC still experienced shortfalls.
- **Regional Failures:**

- o **PJM:** 214 hours/year average, 0.066% normalized unserved energy, 644 hours in worst year, max 36% of load lost.
- o **SPP:** 48 hours/year average, 0.008% normalized unserved energy, max 19% load lost.
- o **ERCOT:** 20 average hours, 0.028% normalized unserved energy, 101 max hours/year, peak shortfall of 27%.
- o **SERC-East:** Generally adequate (avg. 1 hour/year, 0.0003% NUSE), but Elliot storm in 2022 caused 42 hours of shortfall.

The overall takeaway is that avoiding announced retirements improves grid reliability, but shortfalls persist in PJM, SPP, ERCOT, and SERC, particularly in winter.

Required Build

This required build analysis quantifies "hypothetical capacity," defined as power that is 100% reliable and available that is needed to resolve the shortfalls. Known in industry as "perfect capacity," this metric is utilized to avoid the complex decision of selecting specific generation technologies, as that is ultimately an optimization of reliability against cost considerations. Nevertheless, it serves as a valuable indicator, illustrating either the magnitude of a resource gap or the scale of large load that will be unable to interconnect. For the Required Build case, this hypothetical capacity was calculated by adding new generating resources to each region until a target of 0.002% of NUSE is reached.

The table below shows the tuned perfect capacity results. For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year. By 2030, without considering any generation retirements, an additional 12.5 GW of generating capacity is needed across PJM, SPP, and SERC to reduce shortfalls.

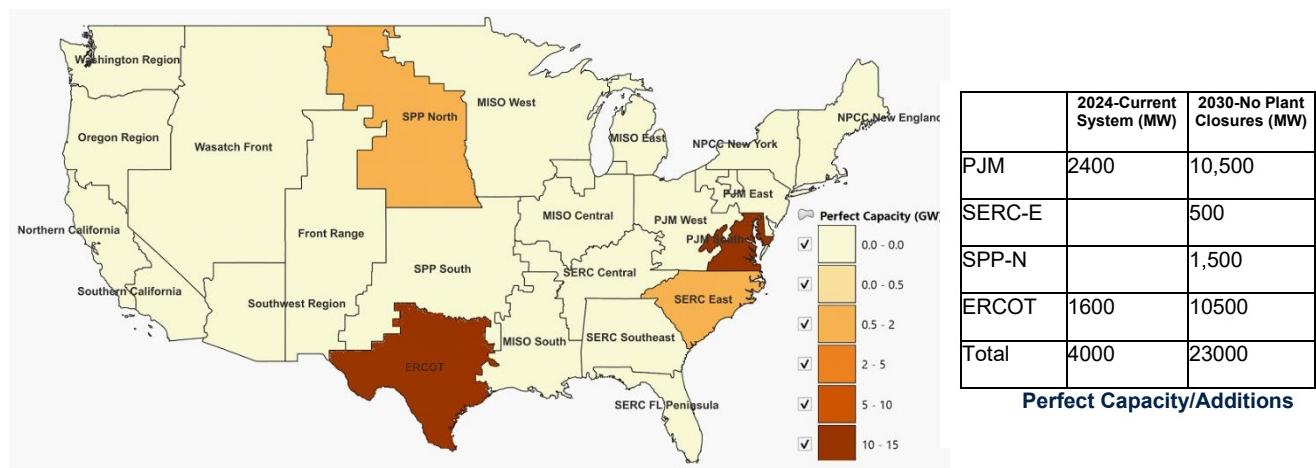


Figure 4. Tuned Perfect Capacity (MW) By Region

1 Modeling Methodology

The methodology uses a zonal PLEXOS¹³ model with hourly time-synchronous datasets for load, generation, and interregional transfer for the 23 U.S. subregions (referred to as TPRs in this study)¹⁴ including ERCOT (see Figure 5 below). While ERCOT operates outside of FERC's general jurisdiction,¹⁵ it provides a valuable case for understanding broader reliability and resource adequacy challenges in the U.S. electric grid, and FPA Section 202(c) allows DOE to issue emergency orders to ERCOT.

We base this analysis on actual weather and power plant outage data from 2007 to 2023 using NERC's ITCS¹⁶ base dataset. DOE specifically decided to start this analysis with the ITCS dataset since it is a complete representation of the interconnected electrical system for the lower 48 and it has been thoroughly reviewed by industry experts in a public and transparent process. DOE has in turn made modifications to the dataset to fit the needs of this study. The contents of this section focus on those modifications which DOE implemented for purposes of this study.

PLEXOS is an industry-trusted simulation tool used for energy optimization, resource adequacy, and production cost modeling. This study leverages PLEXOS' ability to exercise an hourly production cost model to determine the balance between loads, generation, and imports for each region. Modeling was carried out using a deterministic approach that evaluates whether a power system has sufficient resources to meet projected demand under a pre-defined set of conditions which correspond to the past few years of real-world events. The model ultimately determines the amount of unmet load if generation resources and imports are not sufficient for meeting the load in each discrete time period.

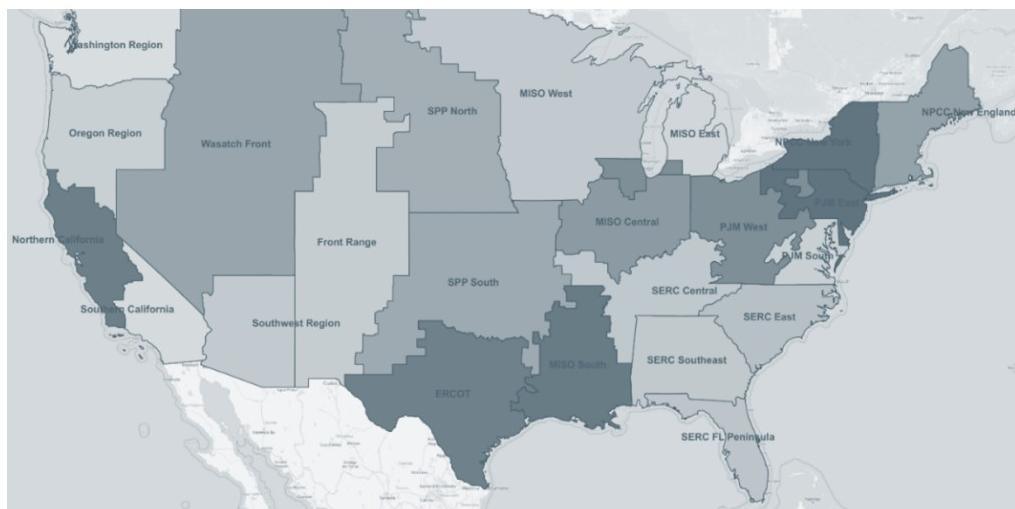


Figure 5. TPRs used in NERC ITCS

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13. Energy Exemplar, "PLEXOS," <https://www.energyexemplar.com/plexos>.
 14. The TPRs match the regional subdivisions in the NERC ITCS study, itself based on FERC's transmission planning regions.
 15. Transmission within ERCOT is intrastate commerce. 16 U.S.C. § 824(b)(1) (provisions applying to "the transmission of electric energy in interstate commerce").
 16. NERC "Integrated Transmission and Capacity System (ITCS)," accessed June 25, 2025, <https://www.nerc.com/pa/RAPA/Pages/ITCS.aspx>.

This methodology developed a current model and series of scenarios to explore how different assumptions impact resource adequacy. This sensitivity analysis includes assumptions regarding load growth, generation build-outs and retirements, and transfer capabilities. By comparing the results of the current model with the scenario results, we can assess how generation retirements and load growth affect future generation needs.

The assessment uses data from 2007–2013 (synthetic weather data) and 2019–2023 (historical data). A brief summary of the methodological assumptions is provided here, with additional details available in the relevant appendixes.

- **Solar and Wind Availability** – Created from historical output from EIA 930 data, with bias correction of any nonhistorical data to match regional capacity factors, as calibrated to EIA 930 data.¹⁷ Synthetic years used 2018 technology characteristics from NREL based on the Variable Energy Potential (reV) model, then mapped to synthetic weather year data. See Appendix A for more details.
- **Thermal Availability** – Calculated according to NERC LTRA capacity data, adjusted for historical outages and derates, primarily with GADS data. GADS data does not capture historical outages caused by fuel supply interruptions.¹⁸
- **Hydroelectric Availability** – Historical outputs are processed by NERC to establish monthly power rating limits and energy budgets, but energy budgets are not enforced in alignment with how they were treated in the ITCS. The team evaluated performance under different energy budget restrictions, but did not find significant differences during peak hours, justifying NERC ITCS assumptions that hydroelectric resources could generally be dispatched to peak load conditions. Later work may benefit from exploring drought scenarios or combinations of weather and hydrological years, where energy budgets may be significantly decreased.
- **Outages and Derates** – Data for the actual data period (2019–2023) are based on historical forced outage rates and deratings. Outage and deratings data for the synthetic period (2007–2013) are based on the historical relationships observed between temperature and outages (see Appendix G of the NERC ITCS Final Report for more information).
- **Load Projections and AI Growth** – Load growth through 2030 is assumed to match NERC 2024 ITCS projections, scaling the 12 weather years to meet 2030 projections. Additional AI and data center load is then added according to reports from EPRI and S&P regarding potential futures.
- **Transfer Capabilities and Imports/Exports** - Each subregion is treated as a “copper plate,” with the transfer capacity between each subregion defined by the availability of transmission pathways. It is an approximation that assumes all resources are connected to a single point, simplifying the transmission system within the model. Subregions are generally assumed to exhaust their own capacity before utilizing capacity available from their neighbors. Once the net remaining capacity is at or below 10 percent of load, the subregion begins to use capacity from a neighbor.

17. See ITCS Final Report, Appendix F, for the method that was implemented to scale synthetic weather years 2007–2013.

18. See ITCS Final Report, Appendix G, for outage and derate methods.

- Imports are assumed to be available up to the minimum total transfer capacity and spare generation in the neighboring subregion.
- To the extent the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario, the model projects an energy shortfall. See “Outputs” in the appendix for more details.
- To ensure that transfers are dispatched only after local resources are exhausted, a wheeling charge of \$1,000 is applied for every megawatt-hour of energy transferred between regions through transmission pathways.
- **Storage** – In alignment with the NERC ITCS methodology, storage was split into pumped hydro and battery storage. Pumped hydro was assumed to have 12 hours duration at rated capacity with 30% round-trip losses, while battery storage was assumed to have four hours and 13% round-trip losses. Storage is dispatched as an optimization to minimize USE and demand response usage under various constraints and is recharged during periods of surplus energy.
- **Demand Response** – Demand Response (DR) is treated as a supply-side resource and dynamically scheduled after all other regional resources and imports are exhausted. It is modeled with both capacity (MW) and energy (MWh) limitations and assumed to have three hours of availability at capacity but could be spread across more than three hours up to the energy limit. DR capacity was based on LTRA Form A data submissions for “Controllable and Dispatchable Demand Response – Available”, or firm, controllable DR capacity.
- **Retirements** – Retirements as per the NERC LTRA 2024 model. To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant level data are used to tabulate generation retirement or addition capacity for each ITCS region and NERC assessment area. Disaggregation fractions are then calculated by technology based on planned retirements through 2030. See Appendix B for further information. Retirements are categorized into two categories:
 1. *Announced Retirements*: Includes both confirmed retirements and announced retirements. Confirmed retirements are generators formally recognized by system operators as having started the official retirement process and are assumed to retire on their expected date. To go from LTRA regions to ITCS regions, weighting factors are derived in the same way as in the generation set, based on EIA retirement data. In addition to confirmed retirements, announced retirements are generators that have publicly stated retirement plans that have not formally notified system operators and initiated the retirement process. This disaggregation method for announced retirements mirrors used for confirmed retirements.¹⁹
 2. *None*: Removes all retirements (after 2024) for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirement contributes to some of the adequacy challenges in some regions.
- **Additions** – Assumes only projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built. This data is based on projects

19. If announced retirements were less than or equal to confirmed retirements, the model adjusted the announced retirement to equal confirmed.

designated as Tier 1 in the NERC 2024 LTRA and are mapped to ITCS regions with EIA 860-derived weighting factors similar to those described for the retirements above. See Appendix A for further information.

- **Perfect Capacity Required** - Estimates perfect capacity (which is idealized capacity that has no outages or profile and is described in Section 2) until we reach a pre-defined reliability target. We used a metric of NUSE given the deterministic nature of the model, to be consistent with evolving metrics, and to be consistent with NERC's recent LTRAs. We targeted NUSE of below 0.002% for each region.

1.1 Modeling Resource Adequacy

This model calculates several reliability metrics to assess resource adequacy. These metrics were calculated using PLEXOS simulation outputs, which report the USE (in MWh) for all 8,760 hourly periods in each of the 12 weather years:

- **USE** refers to the amount of electricity demand that could not be met due to insufficient generation and/or transmission capacity. Several USE-derived indicators were considered:
 - *Normalized USE (percentage %)*: The total amount of unserved load over 12 years of weather data, normalized by dividing by total load, and reported as a percentage.²⁰
 - *Mean Annual USE (GWh)*: The 12-year average of each region's total USE in each weather year. This mean value represents the average annual USE across weather variability.
 - *Mean Max Unserved Power (GW)*: The 12-year average of each region's maximum USE value in each weather year. This mean value characterizes the typical non-coincident peak stress on system reliability.
 - *% Max Unserved Power*: The Mean Max Unserved Power expressed as a percentage of the average native load during those peak unserved hours for each region. This percentage value provides a normalized measure of the severity of peak unserved events relative to demand.
 - *Total number of customers without power*: The Mean Max Unserved Power expressed as the equivalent number of typical U.S. persons assuming a ratio of 17,625 persons/MW lost. This estimation contextualizes the effects of the outage on average Americans.
- **Loss of Load Hours (LOLH)** refers to the number of hours during which the system experiences USE (i.e., any hour with non-zero USE). Two LOLH-based indicators were considered:

20. NUSE can be reported as parts per million or as a percentage (or parts per hundred); though for power system reliability, this would include several zeros after the decimal point.

- *Mean Annual LOLH:* for each weather year and *TPR*, we count the total number of hours with USE across all 8,760 hours, and we then take the average of those 12 totals. *Annual LOLH Distribution* is represented in box and whisker plots for 12 samples, each sample corresponding to a unique weather year.
- *Max Consecutive LOLH (hours)²¹:* The longest continuous period with reported USE in each weather year.

It should be noted that USE is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system. Rather, it represents the unrealizable AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth. These numbers are used as indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need.

This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.

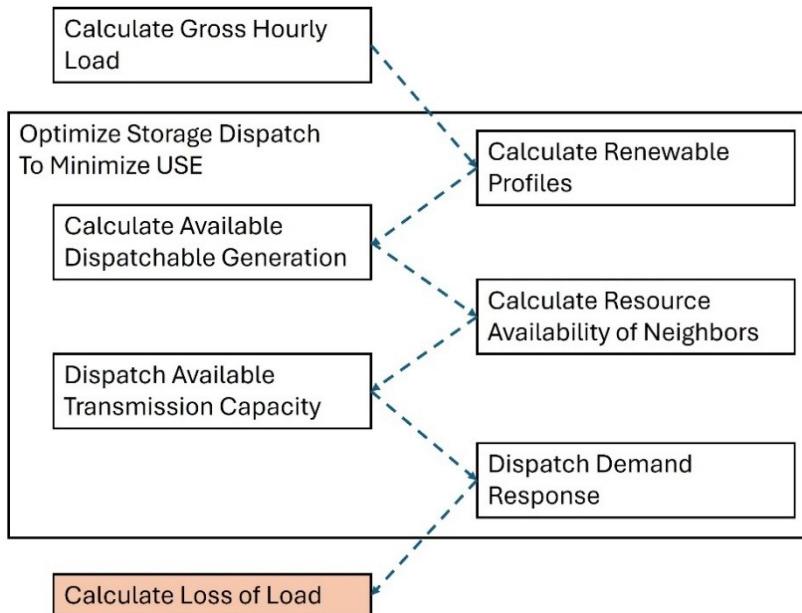


Figure 6. Simplified Overview of Model

21. One caveat on the maximum consecutive LOLH and max USE values is in how storage is dispatched in the model. Storage is dispatched to minimize the overall USE and is indifferent to the peak depth or the duration of the event. This may construe some of the max USE and max consecutive LOLH values to be higher than if storage was dispatched to minimize these values.

1.2 Planning Years and Weather Years

For the planning year (2030), historical weather year data are applied based on conditions between 2007 and 2024 to calculate load, wind and solar generation, and hydro generation. Dispatchable capacity (including dispatchable hydro capacity) is calculated through adjustment of the 2024 LTRA capacity data for historical outages from GADS data. Storage assets are scheduled to arbitrage hourly energy margins or else charge during periods of high energy margins (surplus resources) and discharge during periods of lower energy margins.

1.3 Load Modeling

Data Center Growth

Several utilities and financial and industry analysts identify data centers, particularly those supporting AI workloads, as a key driver of electricity demand growth. Multiple organizations have developed a wide range of projections for U.S. data center electricity use through 2030 and beyond, each using distinct methodologies tailored to their institutional expertise.

These datasets were used to explore reasonable boundaries for what different parts of the economy envision for the future state of AI and data center (AI/DC) load growth. For the purposes of this study, rather than focusing on any specific analysis, a more generic sweep was performed across AI/DC load growth and the various sensitivities that fit within those assumptions, as summarized below:

- McKinsey & Company projects ~10% annual growth in U.S. data center electricity demand, reaching 2,445 TWh by 2050. Their model blends internal scenarios with public signals, including announced projects, capital investment, server shipments, and chip-level power trends, supported by third-party market data.
- Lawrence Berkeley National Laboratory (LBNL) uses a bottom-up approach based on historical and projected IT equipment shipments, paired with assumptions on power draw, utilization, and infrastructure efficiency (PUE, WUE). Their projections through 2028 account for AI hardware adoption, operational shifts, and evolving cooling technologies.
- EPRI combines public data, expert input, and historical trends to define four national growth scenarios, low to higher, for 2023–2030, reflecting data processing demand, efficiency improvements, and AI-driven load impacts.
- S&P Global merges technology and power-sector models, evaluating grid readiness and facility growth under varying demand scenarios. Their forecasts consider AI adoption, efficiency trends, grid and permitting constraints, on-site generation, and offshoring risk, resulting in a wide range of outcomes.

These projections show wide variation, with 2030 electricity demand ranging from approximately 35 GW to 108 GW of average load. Given this uncertainty, including differences in hardware intensity, thermal management, siting assumptions, and behind-the-meter generation, the modeling team adopted a national midpoint assumption of approximately 50 GW by 2030.

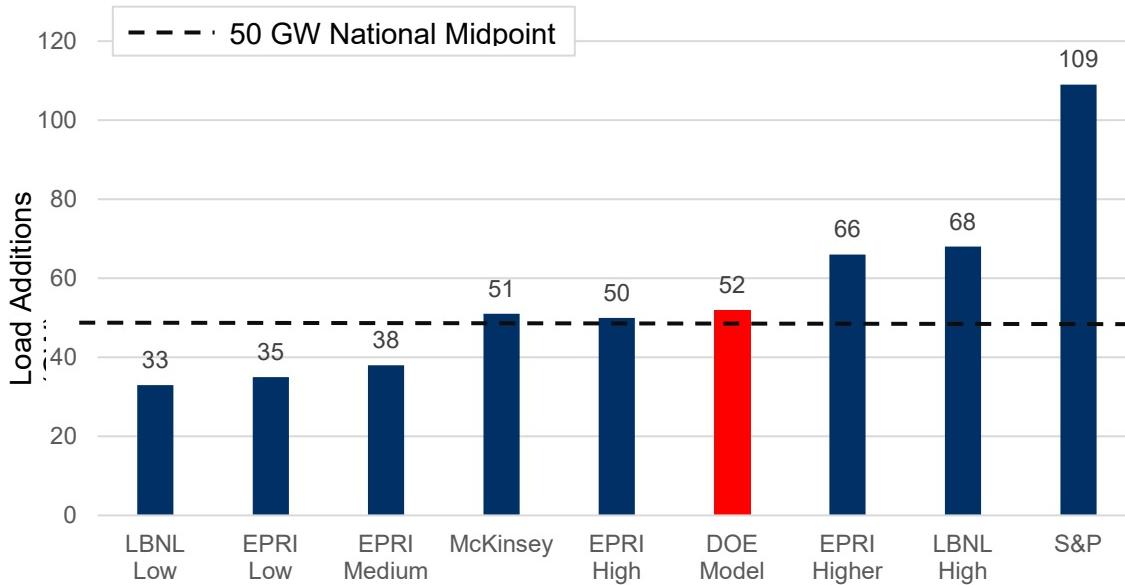


Figure 7. 2024 to 2030 Projected Data Center Load Additions

Figure 2 above displays a benchmark reflecting the median across major studies and aligns with central projections from EPRI and LBNL. Using a single planning midpoint avoids double counting and enables consistent load allocation across national transmission and resource adequacy models.

Data Center Allocation Method

To allocate the 50 GW midpoint regionally, the team used state-level growth ratios from S&P's forecast. These ratios reflect factors such as infrastructure, siting trends, and projected market activity. The modeling team mapped the state-level projections to NERC TPRs, ensuring transparent and repeatable regional allocation. While other methods exist, this approach ensured consistency with the broader modeling framework.

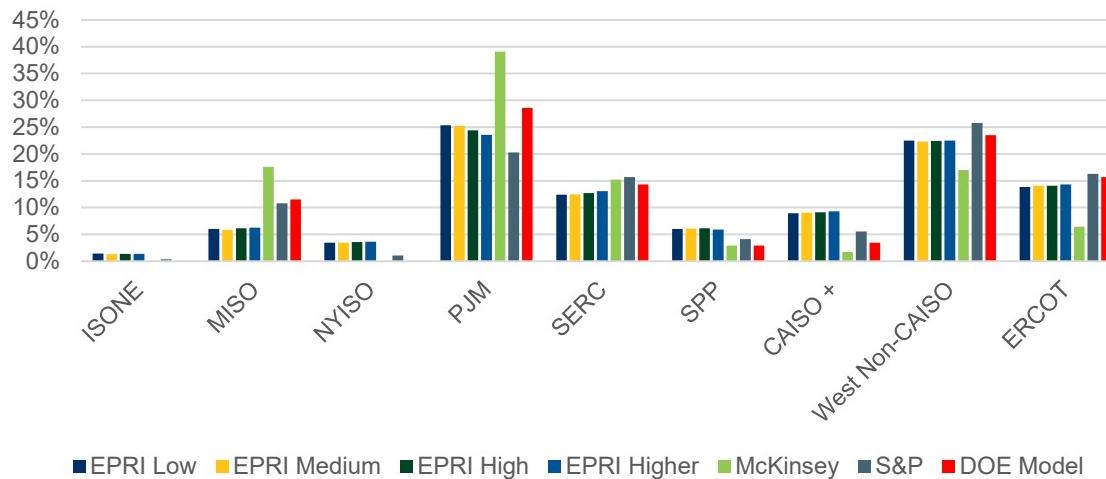


Figure 8. New Data Center Build (% Split by ISO/RTO) (2030 Estimated)

Non-Data Center Load Modeling

The current electricity demand projections were built from NERC data, using historical load (2019–2023) and simulated weather years (2007–2013). These were adjusted based on the EIA's 2022 energy forecast. To estimate 2030 demand, the team interpolated between 2024 and 2033, scaling loads to reflect energy use and seasonal peaks. NERC provided datasets to address anomalies and include behind-the-meter and USE.

Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC LTRA forecast, for example, the 2024 LTRA saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.

Overall Impact on Projected Peak Load

As a result of the methods applied above, the average year co-incident peak load is projected to grow from a current average peak of 774 GW to 889 GW in 2030. This represents a 15% increase or 2.3% growth rate per year. Excluding the impact of data centers, this would amount to a 51GW increase from 774 GW to 826 GW which represents a 1.1% annual growth rate.

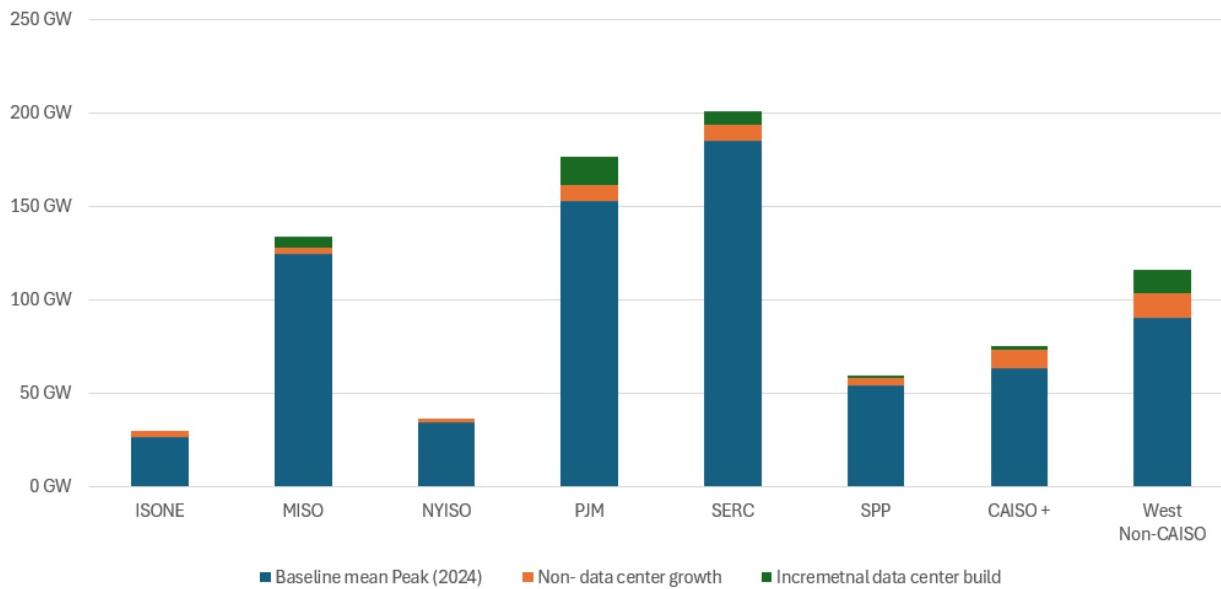


Figure 9. Mean Peak Load by RTO (Current Case vs 2030 Case)

1.4 Transfer Capabilities and Import Export Modeling

The methodology assumes electricity moves between subregions, when conditions start to tighten. Each region has a certain amount of capacity available, and the methodology determines if there is enough to meet the demand. When regions reach a “Tight Margin Level” of 10% of capacity, i.e., if a region’s available capacity is less than 110% of load, it will start transferring from other regions if capacity is available. A scarcity factor is used to determine which regions to transfer from and at what fraction – those with a greater amount of reserve capacity will transfer more. A region is only allowed to export above when it is above the Tight Margin Level.

Total Transfer Capability (TTC) was used and is the sum of the Base Transfer Level and the First Contingency Incremental Transfer Capability. These were derived from scheduled interchange tables or approximated from actual line flows. It should be noted that the TTC does not represent a single line, but rather multiple connections between regions. It is similar to path limits used by many entities but may have different values.

Due to data and privacy limitations, the Canadian power system was not modeled directly as a combination of generation capacity and demand. Instead, actual hourly imports were used from nearly 20 years of historical data, along with recent trends (generally less transfers available during peak hours), to develop daily limits on transfer capabilities. See Appendix B for more details on Canadian transfer limits.

1.5 Perfect Capacity Additions

To understand how much capacity may need to be added to reach approximate reliability targets, we tuned two scenarios by adding hypothetical perfect capacity to reach the reliability threshold based on NUSE.²² Today, NERC uses a threshold of 0.002% to indicate regions are at high risk of resource adequacy shortfalls. In addition, several system operators, including the Australia Energy Market Operator and Alberta Electric System Operator, are using NUSE thresholds in the range of 0.001% to 0.003%. Several U.S. entities are considering lower thresholds for U.S. power systems in the range of 0.0001% to 0.0002%.²³

For this analysis, we target NUSE below 0.002% for each region to align with NERC definitions. We iteratively ran the model, hand-tuning the “perfect capacity” to be as small as possible while reaching NUSE values below 0.002% in all regions.²⁴ As the work was done by hand with a limited number of iterations (15), this should not be considered the minimum possible capacity to accomplish these targets. Further, because the perfect capacity can be located in various places, there would be multiple potential solutions to the problem. These scenarios represent the approximate quantity of perfect capacity each region would require (beyond announced retirements and mature generation additions only) that would lead to Medium or Low risk based on the NERC metrics for USE.

Due to some regions with zero USE, the tuned cases do not reach the same level of adequacy, where the national average is 0.00045% vs. 0.00013%. Due to transmission and siting selection of perfect capacity, there could be many solutions.

22. We are not using the standard term “expected unserved energy” because we are not running a probabilistic model, so we do not have the full understanding of long-term expectations

23. MISO, “Resource Adequacy Metrics and Criteria Roadmap,” December 2024.

<https://cdn.misoenergy.org/Resource%20Adequacy%20Metrics%20and%20Criteria%20Roadmap667168.pdf>.

24. NERC, “Evolving Criteria for a Sustainable Power Grid,” July 2024.

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Evolving_Planning_Criteria_for_a_Sustainable_Power_Grid.pdf.

2 Regional Analysis

This section presents more regional details on resource adequacy according to this analysis. For each of the nine Regional Transmission Organizations (RTOs) and sub-regions, comprehensive summaries are provided of reliability metrics, load assumptions, and composition of generation stacks.

2.1 MISO²⁵

In the current system model and the No Plant Closures cases, MISO did not experience shortfall events. MISO's minimum spare capacity in the tightest year was negative, showing that adequacy was achieved by importing power from neighbors. In the Plant Closures case, MISO experienced significant shortfalls, with key reliability metrics exceeding each of the threshold criteria defined for the study.

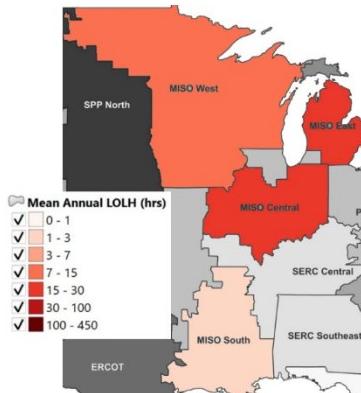


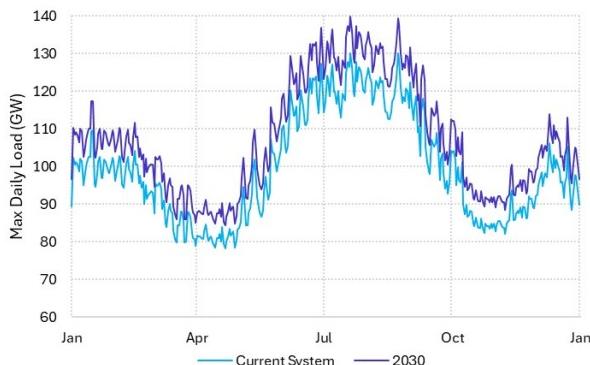
Table 2. Summary of MISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	37.8	-	-
Normalized Unserved Energy (%)	-	0.0211	-	-
Unserved Load (MWh)	-	157,599	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	124	-	-
Normalized Unserved Load (%)	-	0.0702	-	-
Unserved Load (MWh)	-	524,180	-	-

Load Assumptions

MISO's peak load was roughly 130 GW in the current model and projected to increase to roughly 140 GW by 2030. Approximately 6 GW of this relates to new data centers being installed (12% of U.S. total).

25. Following the initial data collection for this report, MISO issued its 2025 Summer Reliability Assessment. Based on that report, NERC revised evaluations from its 2024 LTRA and reclassified the MISO footprint from being an 'elevated risk' to 'high risk' in the 2028–2031 timeframe, depending on new resource additions/retirements. While DOE's analysis is based on the previously reported figures, DOE is committed to assessing the implications of updated data on overall resource adequacy and providing technical updates on findings, as appropriate.



Subregion	2024	2030
MISO-W	37,913	40,981
MISO-C	35,387	39,243
MISO-S	36,476	38,596
MISO-E	23,167	23,758
Total	130,136	139,846

Figure 10. MISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 207 GW.²⁶ In 2030, 21 GW of new capacity was added leading to 228 GW of capacity in the No Plant Closures case. In the Plant Closures case, 32 GW of capacity was retired such that net retirements in the Plant Closures case were -11 GW, or 196 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
MISO-W	71,612	67,453	77,605
MISO-C	51,982	47,735	58,823
MISO-S	54,511	52,756	59,710
MISO-E	29,213	28,105	32,255
Total	207,319	196,049	228,393

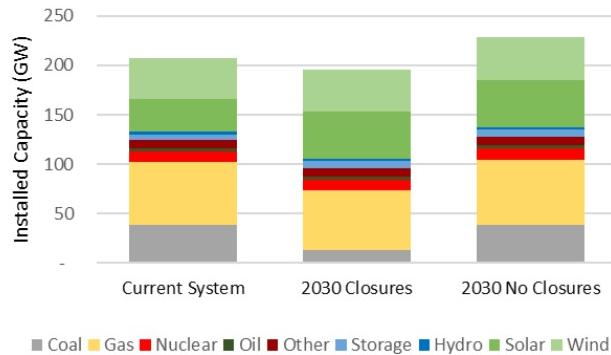


Figure 11. MISO Generation Capacity by Technology and Scenario

MISO's generation mix was comprised primarily of natural gas, coal, wind, and solar. In 2024, natural gas comprised 31% of nameplate, wind comprised 20%, coal 18%, and solar 14%. In 2030, most retirements come from coal and natural gas while additions occur for solar, batteries, and wind. In addition, the model assumed 3 GW of rooftop solar and 8 GW of demand response.

26. The total installed capacity numbers reported in this regional analysis section do not reflect the generating capability of all resources during stress conditions.

Table 3. Nameplate Capacity by MISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	37,914	64,194	11,127	2,867	8,717	5,427	2,533	32,826	41,715	207,319
MISO-W	12,651	13,608	2,753	1,491	2,613	200	777	8,109	29,411	71,612
MISO-C	15,050	10,307	2,169	494	2,211	1,272	769	12,361	7,350	51,982
MISO-S	5,493	31,052	5,100	589	2,469	54	845	8,315	596	54,511
MISO-E	4,720	9,227	1,105	292	1,424	3,901	143	4,042	4,359	29,213
Additions	0	2,535	0	330	0	1,929	0	14,354	1,926	21,074
MISO-W	0	537	0	172	0	374	0	3,552	1,358	5,993
MISO-C	0	407	0	57	0	934	0	5,103	339	6,841
MISO-S	0	1,226	0	68	0	9	0	3,868	27	5,199
MISO-E	0	364	0	34	0	611	0	1,831	201	3,042
Closures	(24,913)	(6,597)	0	(324)	(140)	(16)	(83)	0	(272)	(32,345)
MISO-W	(8,313)	(1,398)	0	(168)	(56)	0	(25)	0	(192)	(10,152)
MISO-C	(9,889)	(1,059)	0	(56)	(7)	(3)	(25)	0	(48)	(11,088)
MISO-S	(3,609)	(3,191)	0	(67)	(55)	(0)	(28)	0	(4)	(6,954)
MISO-E	(3,102)	(948)	0	(33)	(21)	(13)	(5)	0	(28)	(4,150)

2.2 ISO-NE

In the current system model and the No Plant Closures case, ISO-NE did not experience shortfall events. The region maintained adequacy throughout the study period through reliance on imports. In the Plant Closures case, ISO-NE still did not exceed any key reliability thresholds, despite moderate retirements. This finding is partly due to the absence of additional AI or data center load growth modeled in the region. Accordingly, no additional perfect capacity was deemed necessary by 2030 to meet the study's reliability standards.

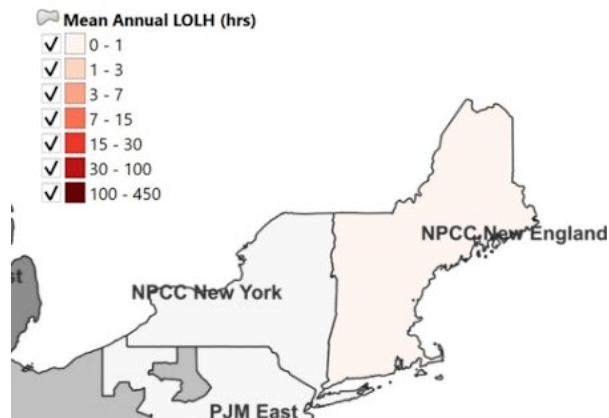


Table 4. Summary of ISO-NE Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	-	-	-
Normalized Unserved Energy (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	-	-	-
Normalized Unserved Load (%)	-	-	-	-
Unserved Load (MWh)	-	-	-	-
Max Unserved Load (MW)	-	-	-	-

Load Assumptions

ISO-NE's peak load was roughly 28 GW in the current model and projected to increase to roughly 31 GW by 2030. No additional AI/DCs were projected to be installed.



Figure 12. ISO-NE Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 40 GW. In 2030, 5.5 GW of new capacity was added leading to 45.5 GW of capacity in the No Plant Closures case. In the Plant Closures case, 2.7 GW of capacity was retired such that net generation change in the Plant Closures case was +11 GW, or 42.8 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ISO-NE	39,979	42,845	45,534
Total	39,979	42,845	45,534

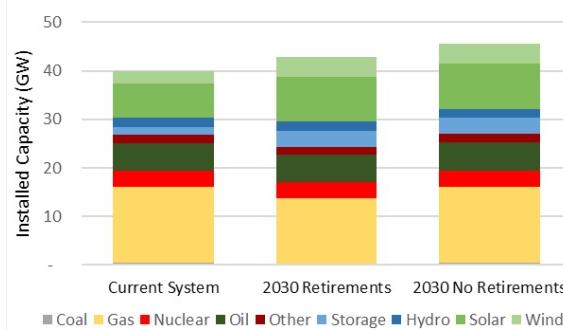


Figure 13. ISO-NE Generation Capacity by Technology and Scenario

ISO-NE's generation mix was comprised primarily of natural gas, solar, oil, and nuclear. In 2024, natural gas comprised 39% of nameplate, solar comprised 17%, oil 14%, and nuclear 8%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed nearly 2 GW of rooftop solar and 1.6 GW of energy storage.

Table 5. Nameplate Capacity by ISO-NE Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	541	15,494	3,331	5,710	1,712	1,628	1,911	7,099	2,553	39,979
ISONE	541	15,494	3,331	5,710	1,712	1,628	1,911	7,099	2,553	39,979
Additions	0	90	0	181	0	1,607	0	2,183	1,495	5,555
ISONE	0	90	0	181	0	1,607	0	2,183	1,495	5,555
Closures	(534)	(1,875)	0	(203)	(77)	0	0	0	0	(2,690)
ISONE	(534)	(1,875)	0	(203)	(77)	0	0	0	0	(2,690)

2.3 NYISO

In both the current system model and the No Plant Closures case, NYISO maintained reliability and did not exceed any shortfall thresholds. Adequacy was preserved through reliance on imports. In the Plant Closures case, NYISO experienced shortfalls but average annual LOLH remaining well below the 2.4-hour threshold and NUSE under the 0.002% standard. The worst weather year produced only 6 hours of lost load and a peak unserved load of 914 MW. Given the modest impact of retirements and no additional AI/data center load modeled, the study concluded that NYISO would not require additional perfect capacity to remain reliable through 2030.

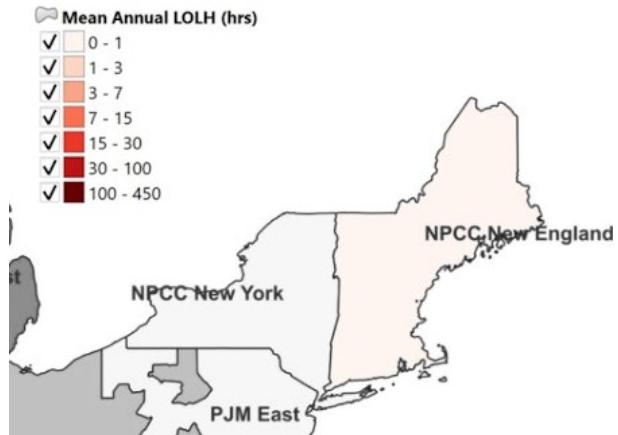


Table 6. Summary of NYISO Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.2	0.5	-	-
Normalized Unserved Energy (%)	0.00001	0.0001	-	-
Unserved Load (MWh)	18	209	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	2	6	-	-
Normalized Unserved Load (%)	0.0001	0.0013	-	-
Unserved Load (MWh)	216	2,505	-	-
Max Unserved Load (MW)	194	914	-	-

Load Assumptions

NYISO's peak load was roughly 36 GW in the current system model and projected to increase to roughly 38 GW by 2030. No additional AI/DCs were projected to be installed.

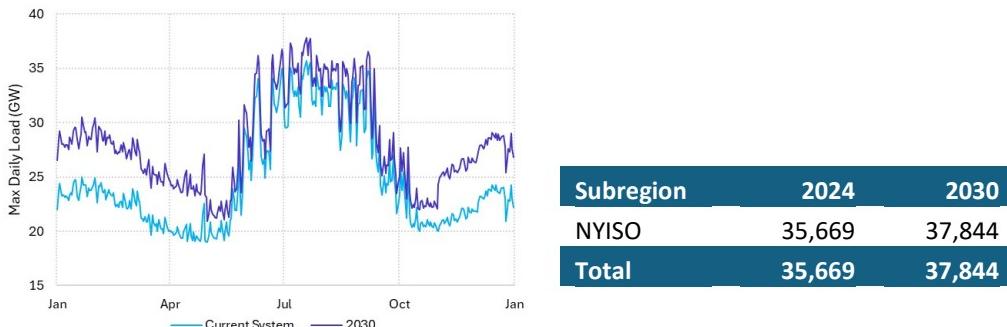


Figure 14. NYISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 46 GW. In 2030, 5.5 GW of new capacity was added leading to 51 GW of capacity in the No Plant Closures case. In the Plant Closures case, 1 GW of capacity was retired such that net generation in the Plant Closures case was +4 GW, or 50 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
NYISO	45,924	50,396	51,444
Total	45,924	50,396	51,444

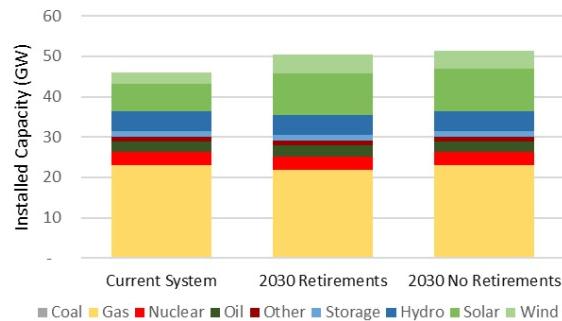


Figure 15. NYISO Generation Capacity by Technology and Scenario

NYISO's generation mix was comprised primarily of natural gas, solar, and hydro. In 2024, natural gas comprised 50% of total nameplate generation, solar comprised 14%, and hydro 11%. In 2030, most retirements come from natural gas while additions occur for solar and wind. The model assumed 6 GW of rooftop solar and nearly 1 GW of demand response.

Table 7. Nameplate Capacity by NYISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	0	22,937	3,330	2,631	1,194	1,460	4,915	6,749	2,706	45,924
NYISO	0	22,937	3,330	2,631	1,194	1,460	4,915	6,749	2,706	45,924
Additions	0	0	0	15	0	0	0	3,604	1,902	5,521
NYISO	0	0	0	15	0	0	0	3,604	1,902	5,521
Closures	0	(1,030)	0	(19)	0	0	0	0	0	(1,049)
NYISO	0	(1,030)	0	(19)	0	0	0	0	0	(1,049)

2.4 PJM

In the current system model, PJM experienced shortfalls, but they were below the required threshold. In the No Plant Closures case, shortfalls increased dramatically, with 214 average annual LOLH and peak unserved load reaching 17,620 MW, indicating growing strain even without retirements. In the Plant Closures case, reliability metrics worsened significantly, with annual LOLH surging to over 430 hours per year and NUSE reaching 0.1473%—over 70 times the accepted threshold. During the worst weather year, 1,052 hours of load were shed. To restore reliability, the study found that PJM would require 10,500 MW of additional perfect capacity by 2030.

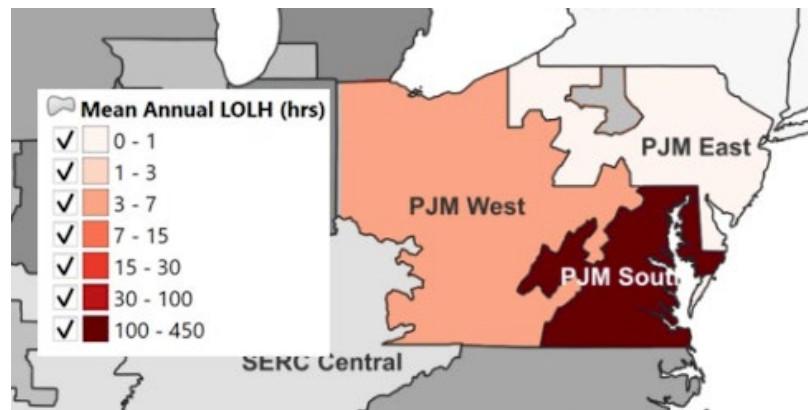
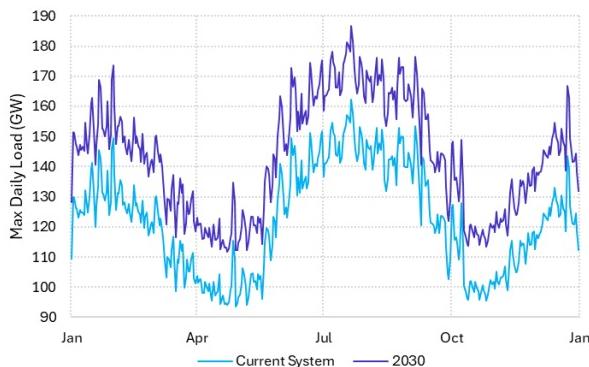


Table 8. Summary of PJM Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	2.4	430.3	213.7	1.4
Normalized Unserved Energy (%)	0.0008	0.1473	0.0657	0.0003
Unserved Load (MWh)	6,891	1,453,513	647,893	2,536
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	29	1,052	644	17
Normalized Unserved Load (%)	0.0100	0.4580	0.2703	0.0031
Unserved Load (MWh)	82,687	1,453,513	647,893	2,536
Max Unserved Load (MW)	4,975	21,335	17,620	4,162

Load Assumptions

PJM's peak load was roughly 162 GW in the current system model and projected to increase to roughly 187 GW by 2030. Approximately 15 GW of this relates to new AI/DC being installed (29% of U.S. total), primarily in PJM-S.



Subregion	2024	2030
PJM-W	81,541	92,378
PJM-S	39,904	51,151
PJM-E	41,003	43,118
Total	162,269	186,627

Figure 16. PJM Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 215 GW. In 2030, 39 GW of new capacity was added leading to 254 GW of capacity in the No Plant Closures case. In the Plant Closures case, 17 GW of capacity was retired such that net generation in the Plant Closures case was +22 GW, or 237 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
PJM-W	114,467	123,100	135,810
PJM-S	39,951	48,850	50,667
PJM-E	60,221	64,848	67,027
Total	214,638	236,798	253,504

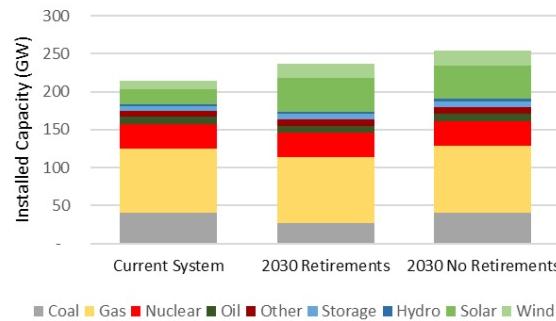


Figure 17. PJM Generation Capacity by Technology and Scenario

PJM's generation mix was comprised primarily of natural gas, coal, and nuclear. In 2024, natural gas comprised 39% of nameplate, coal comprised 19%, and nuclear 15%. In 2030, most retirements come from coal and some natural gas and oil while significant additions occur for solar plus lesser additions of wind, storage, and natural gas. The model assumed 9 GW of rooftop solar and 7 GW of demand response.

Table 9. Nameplate Capacity by PJM Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	39,915	84,381	32,535	9,875	8,248	5,400	3,071	19,495	11,718	214,638
PJM-W	34,917	39,056	16,557	1,933	3,926	383	1,252	6,379	10,065	114,467
PJM-S	2,391	15,038	5,288	3,985	2,303	3,085	1,070	6,430	360	39,951
PJM-E	2,608	30,287	10,690	3,956	2,019	1,932	749	6,686	1,294	60,221
Additions	0	4,499	0	32	317	1,938	0	24,991	7,089	38,866
PJM-W	0	2,082	0	6	135	855	0	12,176	6,089	21,343
PJM-S	0	802	0	13	102	726	0	8,856	218	10,717
PJM-E	0	1,615	0	13	81	357	0	3,958	783	6,806
Closures	(13,253)	(1,652)	0	(1,790)	(11)	0	0	0	0	(16,706)
PJM-W	(11,593)	(765)	0	(350)	(1)	0	0	0	0	(12,710)
PJM-S	(794)	(294)	0	(722)	(6)	0	0	0	0	(1,817)
PJM-E	(866)	(593)	0	(717)	(3)	0	0	0	0	(2,179)

2.5 SERC

In the current system model and the No Plant Closures case, SERC maintained overall adequacy, though some subregions—particularly SERC-East—faced emerging winter reliability risks. In the Plant Closures case, shortfalls became more severe, with SERC-East experiencing increased unserved energy and loss of load hours during extreme cold events, including 42 hours of outages in a single winter storm. The analysis identified that planned retirements, combined with rising winter load from electrification, would stress the system. To restore reliability in SERC-East, the study found that 500 MW of additional perfect capacity would be needed by 2030. Other SERC subregions performed adequately, but continued monitoring is warranted due to shifting seasonal peaks and fuel supply vulnerabilities.

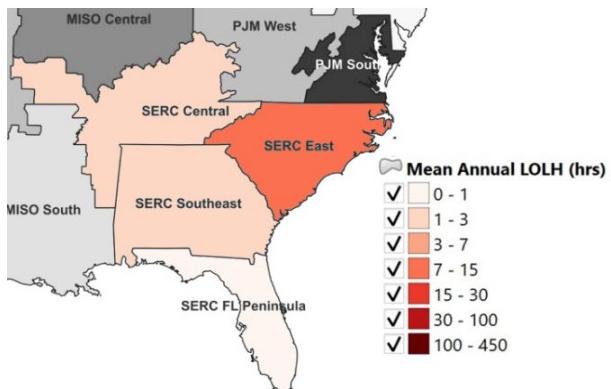
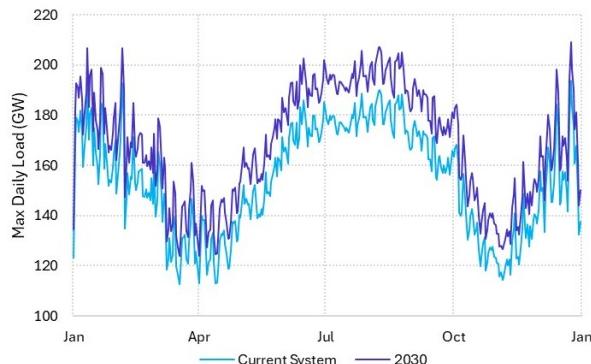


Table 10. Summary of SERC Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	0.3	8.1	1.2	0.8
Normalized Unserved Energy (%)	0.0001	0.0041	0.0004	0.0002
Unserved Load (MWh)	489	44,514	3,748	2,373
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	4	42	14	10
Normalized Unserved Load (%)	0.0006	0.0428	0.0042	0.0026
Unserved Load (MWh)	5,683	465,392	44,977	2,373
Max Unserved Load (MW)	2,373	19,381	6,359	5,859

Load Assumptions

SERC's peak load was roughly 193 GW in the current system model and projected to increase to roughly 209 GW by 2030. Approximately 7.5 GW of this relates to new AI/DCs being installed (14% of U.S. total).



Subregion	2024	2030
SERC-C	50,787	52,153
SERC-SE	48,235	54,174
SERC-FL	58,882	62,572
SERC-E	51,693	56,313
Total	193,654	209,269

Figure 18. SERC Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 254 GW. In 2030, 26 GW of new capacity was added leading to 279 GW of capacity in the No Plant Closures case. In the Plant Closures case, 19 GW of capacity was retired such that net generation change in the Plant Closures case was +7 GW, or 260 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SERC-C	53,978	54,014	59,660
SERC-SE	67,073	64,768	69,478
SERC-FL	72,714	83,127	86,173
SERC-E	59,914	58,513	63,973
Total	253,680	260,423	279,285

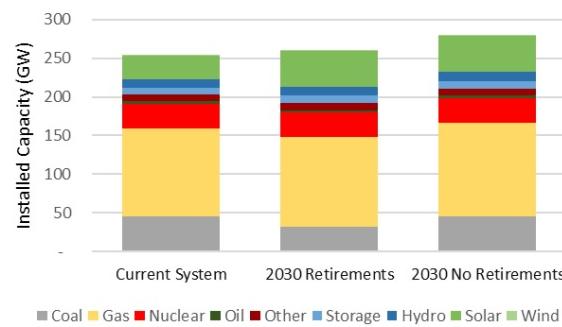


Figure 19. SERC Generation Capacity by Technology and Scenario

SERC's generation mix was comprised primarily of natural gas, coal, nuclear, and solar. In 2024, natural gas comprised 45% of nameplate, coal comprised 18%, nuclear 12%, and solar 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar and some storage. The model assumed 3 GW of rooftop solar and 8 GW of demand response.

Table 11. Nameplate Capacity by SERC Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	45,747	113,334	31,702	4,063	8,779	7,469	11,425	30,180	982	253,680
SERC-C	13,348	20,127	8,280	148	1,887	1,884	4,995	2,328	982	53,978
SERC-SE	13,275	29,866	8,018	915	2,493	1,662	3,260	7,584	0	67,073
SERC-FL	4,346	47,002	3,502	1,957	3,198	538	0	12,172	0	72,714
SERC-E	14,777	16,340	11,902	1,044	1,202	3,384	3,170	8,096	0	59,914
Additions	0	6,898	0	0	381	2,254	0	16,073	0	25,606
SERC-C	0	4,831	0	0	0	80	0	771	0	5,682
SERC-SE	0	906	0	0	19	0	0	3,135	0	4,059
SERC-FL	0	1,161	0	0	218	1,670	0	10,410	0	13,459
SERC-E	0	0	0	0	144	504	0	1,757	0	2,405
Closures	(14,075)	(4,115)	0	(672)	0	0	0	0	0	(18,862)
SERC-C	(4,465)	(1,181)	0	0	0	0	0	0	0	(5,646)
SERC-SE	(5,160)	(124)	0	(176)	0	0	0	0	0	(5,460)
SERC-FL	(1,495)	(1,071)	0	(480)	0	0	0	0	0	(3,046)
SERC-E	(2,955)	(1,739)	0	(16)	0	0	0	0	0	(4,710)

2.6 SPP

In the current system model, SPP experienced shortfalls, but they were below the required threshold. Adequacy was preserved through reliance on imports. In the No Plant Closures case, SPP experienced persistent reliability challenges, with average annual LOLH reaching approximately 48 hours per year and peak hourly shortfalls affecting up to 19% of demand. In the Plant Closures case, system conditions deteriorated further, with unserved energy and outage hours increasing substantially. These shortfalls were concentrated in the northern subregion, which lacks the firm generation and import capacity needed to meet peak winter demand. The analysis determined that 1,500 MW of additional perfect capacity would be needed in SPP by 2030 to restore reliability.

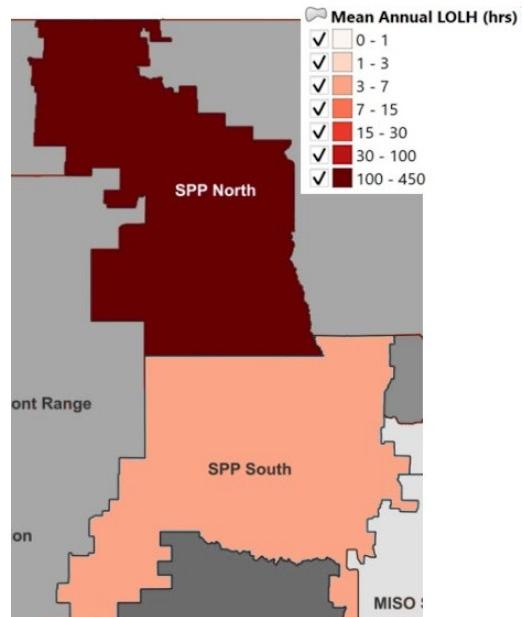
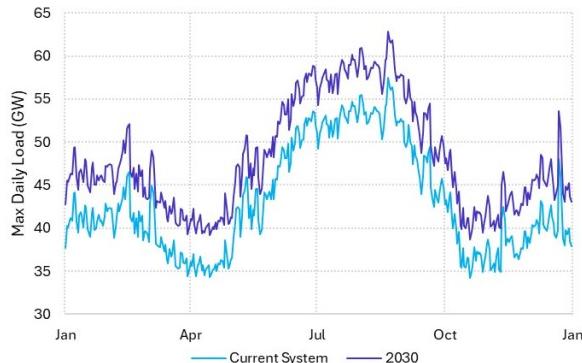


Table 12. Summary of SPP Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	1.7	379.6	47.8	2.4
Normalized Unserved Energy (%)	0.0002	0.0911	0.0081	0.0002
Unserved Load (MWh)	541	313,797	27,697	803
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	20	556	186	26
Normalized Unserved Load (%)	0.0022	0.2629	0.0475	0.0027
Unserved Load (MWh)	6,492	907,518	163,775	9,433
Max Unserved Load (MW)	606	13,263	2,432	762

Load Assumptions

SPP's peak load was roughly 57 GW in the current system model and projected to increase to roughly 63 GW by 2030. Approximately 1.5 GW of this relates to new AI/DCs being installed (3% of U.S. total).



Subregion	2024	2030
SPP-N	12,668	14,676
SPP-S	44,898	48,337
Total	57,449	62,891

Figure 20. SPP Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 95 GW. In 2030, 15 GW of new capacity was added leading to 110 GW of capacity in the No Plant Closures case. In the Plant Closures case, 7 GW of capacity was retired such that net generation change in the 2030 Plant Closures case was +8 GW, or 103 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
SPP-N	20,065	20,679	22,385
SPP-S	75,078	82,451	88,064
Total	95,142	103,130	110,449

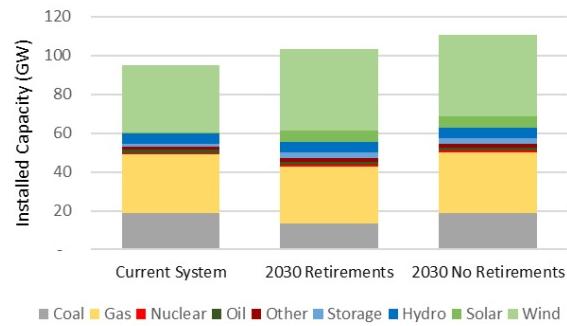


Figure 21. SPP Generation Capacity by Technology and Scenario

SPP's generation mix was comprised primarily of wind, natural gas, and coal. In 2024, wind comprised 36% of nameplate, natural gas comprised 32%, and coal 20%. In the 2030 case, most retirements come from coal and natural gas while additions occur for wind, solar, storage, and natural gas. The model assumed almost no rooftop solar and 1.3 GW of demand response.

Table 13. Nameplate Capacity by SPP Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	18,919	30,003	769	1,626	1,718	1,522	5,123	774	34,689	95,142
SPP-N	5,089	3,467	304	504	519	8	3,041	91	7,041	20,065
SPP-S	13,829	26,536	465	1,121	1,199	1,514	2,082	683	27,649	75,078
Additions	0	1,094	0	7	462	1,390	0	5,288	7,066	15,306
SPP-N	0	126	0	2	114	11	0	633	1,434	2,320
SPP-S	0	968	0	5	348	1,379	0	4,655	5,632	12,987
Closures	(5,530)	(1,732)	0	(56)	0	0	0	0	0	(7,318)
SPP-N	(1,488)	(200)	0	(17)	0	0	0	0	0	(1,705)
SPP-S	(4,042)	(1,532)	0	(39)	0	0	0	0	0	(5,613)

2.7 CAISO+

In the current system and No Plant Closures cases, CAISO+ did not experience major reliability issues, though adequacy was often maintained through significant imports during tight conditions. In the Plant Closures case, however, the region faced substantial shortfalls, particularly during summer evening hours when solar output declines. Average LOLH reached 7 hours per year, and the worst-case year showed load shed events affecting up to 31% of demand. The NUSE exceeded reliability thresholds, signaling the system's vulnerability to high load and low renewable output periods.

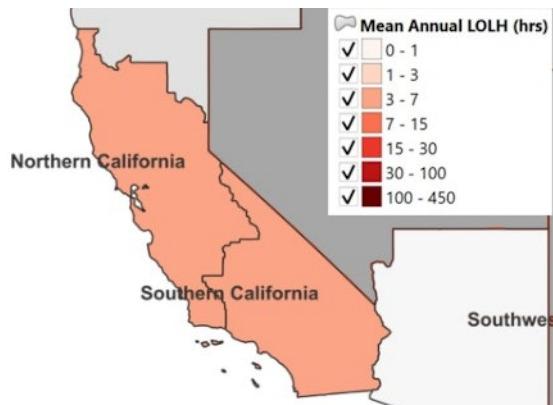
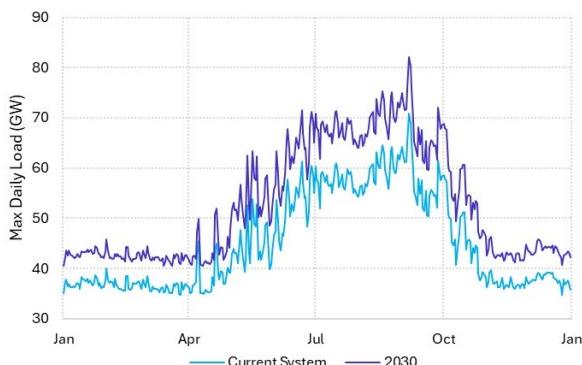


Table 14. Summary of CAISO+ Reliability Metrics

Reliability Metric	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	-	6.8	-	-
Normalized Unserved Energy (%)	-	0.0062	-	-
Unserved Load (MWh)	-	23,488	-	-
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	-	21	-	-
Normalized Unserved Load (%)	-	0.0195	-	-
Unserved Load (MWh)	-	73,462	-	-
Max Unserved Load (MW)	-	12,391	-	-

Load Assumptions

CAISO+'s peak load was roughly 79 GW in the current system model and projected to increase to roughly 82 GW by 2030. Approximately 2 GW of this relates to new AI/DCs being installed (4% of U.S. total).



Subregion	2024	2030
CALI-N	29,366	34,066
CALI-S	41,986	48,666
Total	70,815	82,146

Figure 22. CAISO+ Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was approximately 117 GW. In 2030, 14 GW of new capacity was added leading to 131 GW of capacity in the No Plant Closures case. In the Plant Closures case, 8 GW of capacity was retired such that net closures in the Plant Closures case were +6 GW, or 123 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
CALI-N	47,059	48,897	52,501
CALI-S	69,866	74,041	78,308
Total	116,925	122,938	130,809

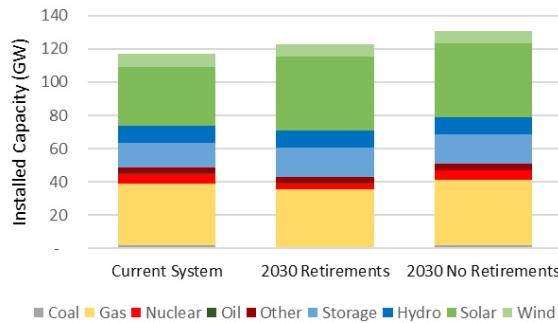


Figure 23. CAISO+ Generation Capacity by Technology and Scenario

CAISO+'s generation mix was comprised primarily of natural gas, solar, storage, and hydro. In 2024, natural gas comprised 32% of nameplate, solar comprised 31%, storage 13%, and hydro 9%. In 2030, most retirements come from coal, natural gas, and nuclear while additions occur for solar and storage. The model assumed 10 GW of rooftop solar and less than 1 GW of demand response.

Table 15. Nameplate Capacity by CAISO+ Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	1,816	37,434	5,582	185	3,594	14,670	10,211	35,661	7,773	116,925
CALI-N	0	12,942	5,582	165	1,872	4,639	8,727	11,759	1,373	47,059
CALI-S	1,816	24,492	0	20	1,722	10,031	1,483	23,902	6,400	69,866
Additions	0	2,126	0	0	92	3,161	0	8,507	0	13,885
CALI-N	0	735	0	0	44	757	0	3,906	0	5,442
CALI-S	0	1,391	0	0	48	2,404	0	4,600	0	8,442
Closures	(1,800)	(3,771)	(2,300)	0	0	0	0	0	0	(7,871)
CALI-N	0	(1,304)	(2,300)	0	0	0	0	0	0	(3,604)
CALI-S	(1,800)	(2,467)	0	0	0	0	0	0	0	(4,267)

2.8 West Non-CAISO

In both the current system and No Plant Closures cases, the West Non-CAISO region maintained adequacy on average. In the Plant Closures case, the region's reliability declined, with annual LOLH increasing and peak shortfalls in the worst year affecting up to 20% of hourly load in some subregions. While overall NUSE normalized unserved energy remained just above the 0.002% threshold, specific areas, especially those with limited local resources and constrained transmission, exceeded acceptable risk levels. These reliability gaps were primarily driven by increasing reliance on variable energy resources without sufficient firm generation.

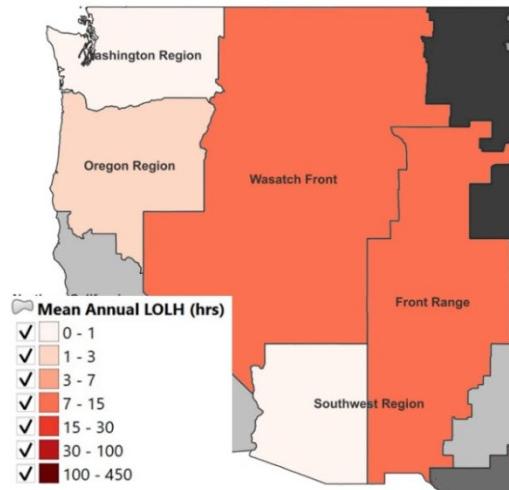
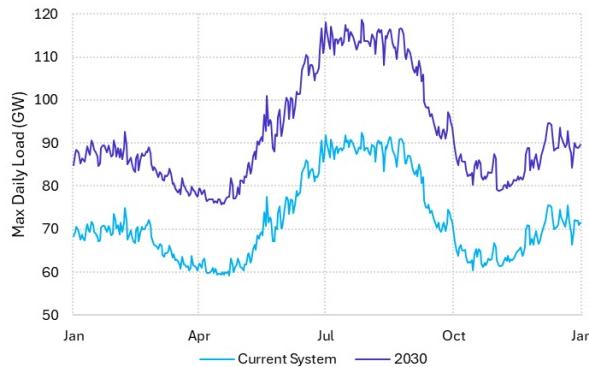


Table 16. Summary of West Non-CAISO Reliability Metrics

Reliability Metric	Current System	Plant Closures	2030 Projection		Required Build
			No Plant Closures		
AVERAGE OVER 12 WEATHER YEARS					
Average Loss of Load Hours	-	17.8		-	-
Normalized Unserved Energy (%)	-	0.0032		-	-
Unserved Load (MWh)	-	21,785		-	-
WORST WEATHER YEAR					
Max Loss of Load Hours in Single Year	-	47		-	-
Normalized Unserved Load (%)	-	0.0098		-	-
Unserved Load (MWh)	-	66,248		-	-
Max Unserved Load (MW)	-	5,071		-	-

Load Assumptions

West Non-CAISO's peak load was roughly 92 GW in the current system model and projected to increase to roughly 119 GW by 2030. Approximately 12 GW of this relates to new AI/DCs being installed (24% of U.S. total).



Subregion	2024	2030
WASHINGTON	20,756	23,187
OREGON	11,337	16,080
SOUTHWEST	23,388	30,169
WASATCH	27,161	35,440
FRONT R	20,119	24,996
Total	92,448	118,657

Figure 24. West Non-CAISO Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 178 GW. In 2030, 29 GW of new capacity was added leading to 207 GW of capacity in the No Plant Closures case. In the Plant Closures case, 13 GW of capacity was retired such that net generation change in the Plant Closures case was 16 GW, or 193 GW of overall installed capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
WASHINGTON	35,207	36,588	37,573
OREGON	19,068	21,689	22,081
SOUTHWEST	42,335	47,022	49,158
WASATCH	42,746	45,175	50,251
FRONT R	38,572	43,011	47,844
Total	177,929	193,485	206,908

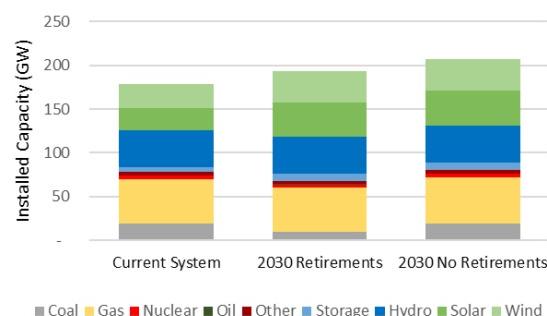


Figure 25. West Non-CAISO Generation Capacity by Technology and Scenario

West Non-CAISO's generation mix was comprised primarily of natural gas, hydro, wind, solar, and coal. In 2024, natural gas comprised 28% of nameplate, hydro comprised 24%, wind 15%, solar 13%, and coal 11%. In 2030, most retirements come from coal and natural gas while additions occur for solar, wind, storage, and natural gas. The model assumed 6 GW of rooftop solar and over 1 GW of demand response.

Table 17. Nameplate Capacity by West Non-CAISO Subregion and Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	19,850	49,969	3,820	644	4,114	5,104	42,476	24,652	27,298	177,929
WASHINGTON	560	3,919	1,096	17	595	489	24,402	1,438	2,690	35,207
OREGON	0	3,915	0	6	456	482	8,253	2,517	3,440	19,068
SOUTHWEST	4,842	17,985	2,724	323	1,316	2,349	1,019	8,093	3,685	42,335
WASATCH	7,033	14,061	0	87	1,433	1,194	7,587	7,299	4,052	42,746
FRONT R	7,415	10,089	0	211	314	590	1,215	5,306	13,432	38,572
Additions	0	2,320	0	1	8	2,932	0	14,759	8,959	28,979
WASHINGTON	0	246	0	0	0	109	0	1,059	952	2,366
OREGON	0	246	0	0	0	150	0	1,399	1,218	3,013
SOUTHWEST	0	309	0	0	0	2,338	0	3,578	599	6,823
WASATCH	0	884	0	0	7	233	0	4,946	1,435	7,505
FRONT R	0	634	0	0	0	102	0	3,779	4,756	9,271
Closures	(9,673)	(2,540)	0	(6)	(311)	(170)	(627)	0	(95)	(13,422)
WASHINGTON	(317)	(195)	0	(0)	(66)	(28)	(369)	0	(11)	(986)
OREGON	0	(195)	0	(0)	(58)	0	(125)	0	(14)	(392)
SOUTHWEST	(1,185)	(951)	0	0	0	0	0	0	0	(2,136)
WASATCH	(3,978)	(699)	0	(2)	(178)	(89)	(115)	0	(16)	(5,077)
FRONT R	(4,194)	(501)	0	(4)	(8)	(53)	(18)	0	(54)	(4,832)

2.9 ERCOT

In the current system model, ERCOT exceeded reliability thresholds, with 3.8 annual Loss of Load Hours and a NUSE of 0.0032%, indicating stress even before future retirements and load growth. In the No Plant Closures case, conditions worsened as average LOLH rose to 20 hours per year and the worst-case year reached 101 hours, driven by data center growth and limited dispatchable additions. The Plant Closures case intensified these risks, with average annual LOLH rising to 45 hours per year and unserved load reaching 0.066%. Peak shortfalls reached 27% of demand, with outages concentrated in winter when generation is most vulnerable. To meet reliability targets, ERCOT would require 10,500 MW of additional perfect capacity by 2030.

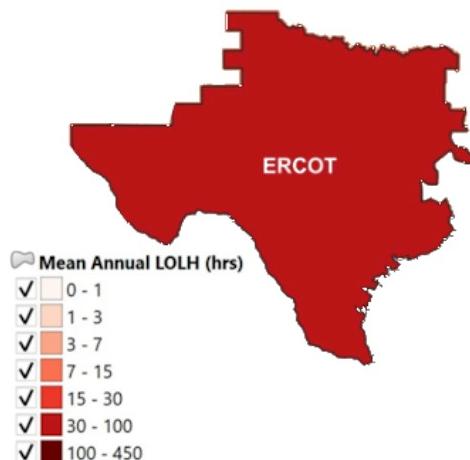
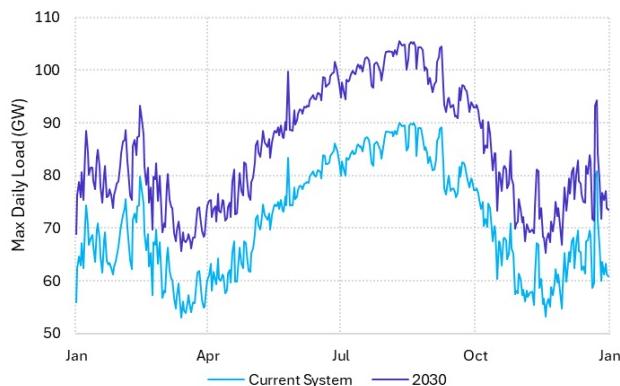


Table 18. Summary of ERCOT Reliability Metrics

Reliability Metric	2030 Projection			
	Current System	Plant Closures	No Plant Closures	Required Build
AVERAGE OVER 12 WEATHER YEARS				
Average Loss of Load Hours	3.8	45.0	20.3	1.0
Normalized Unserved Energy (%)	0.0032	0.0658	0.0284	0.0008
Unserved Load (MWh)	15,378	397,352	171,493	4,899
WORST WEATHER YEAR				
Max Loss of Load Hours in Single Year	30	149	101	12
Normalized Unserved Load (%)	0.0286	0.02895	0.01820	0.0098
Unserved Load (MWh)	136,309	1,741,003	1,093,560	58,787
Max Unserved Load (MW)	10,115	27,156	23,105	8,202

Load Assumptions

ERCOT's peak load was roughly 90 GW in the current system model and projected to increase to roughly 105 GW by 2030. Approximately 8 GW of this relates to new data centers being installed (62% of U.S. total).



Subregion	2024	2030
ERCOT	90,075	105,485
Total	90,075	105,485

Figure 26. ERCOT Max Daily Load in the Current System versus 2030

Generation Stack

Total installed generating capacity for 2024 was 157 GW. In 2030, 55 GW of new capacity was added leading to 213 GW of capacity in the No Plant Closures case. In the Plant Closures case, 4 GW of capacity was retired such that net generation change in the Plant Closures case was +51 GW, or 208 GW of overall nameplate capacity on the system.

Subregion	Current System	2030 Plant Closures	2030 No Plant Closures
ERCOT	157,490	208,894	212,916
Total	157,490	208,894	212,916

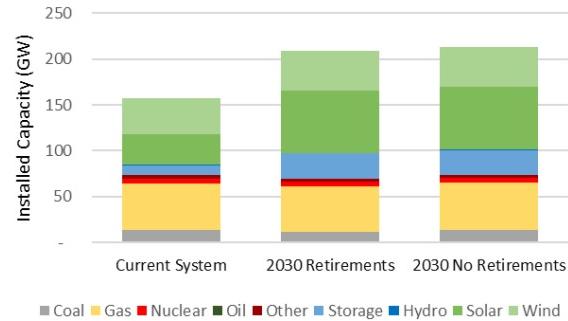


Figure 27. ERCOT Generation Capacity by Technology and Scenario

ERCOT's generation mix was comprised primarily of natural gas, wind, and solar. In 2024, natural gas comprised 32% of nameplate, wind comprised 25%, and solar 22%. In 2030, most retirements come from coal and natural gas while additions occur for solar, storage, and wind. The model assumed 2.5 GW of rooftop solar and 3.5 GW of demand response.

Table 19. Nameplate Capacity for ERCOT and by Technology (MW)

	Coal	Gas	Nuclear	Oil	Other	Storage	Hydro	Solar	Wind	Total
2024	13,568	50,889	4,973	10	3,627	10,720	583	33,589	39,532	157,490
ERCOT	13,568	50,889	4,973	10	3,627	10,720	583	33,589	39,532	157,490
Additions	0	569	0	0	0	16,538	0	34,681	3,638	55,426
ERCOT	0	569	0	0	0	16,538	0	34,681	3,638	55,426
Closures	(2,000)	(2,022)	0	0	0	0	0	0	0	(4,022)
ERCOT	(2,000)	(2,022)	0	0	0	0	0	0	0	(4,022)

Appendix A - Generation Calibration and Forecast

The study team started with the grid model from the NERC ITCS, which was published in 2024 with reference to NERC 2023 LTRA capacity.²⁷ This zonal ITCS model serves as the starting point for the network topology (covering 23 U.S. regions), transmission capacity between zones, and general modeling assumptions. The resource mix and retirements in the ITCS model were updated for this study to reflect the various 2030 scenarios discussed previously. Prior to developing the 2030 scenarios, the study team also updated the 2024 ITCS model to ensure consistency in the current model assumptions.

2024 Resource Mix

Because there were noted changes in assumed capacity additions between the 2023 and 2024 LTRAs²⁸, the ITCS model was updated with the 2024 LTRA data, provided directly by NERC to the study team. The 2024 LTRA dataset, reported at the NERC assessment area level—which is more aggregated in some areas than the ITCS regional structure (covering 13 U.S. regions; see Figure A.1)—includes both existing resource capacities²⁹ and Tier 1, 2, and 3 planned additions for each year from 2024 to 2033. As explained below, to incorporate this data into the ITCS model, a mapping process was developed to disaggregate generation capacities from the NERC assessment areas to the more granular ITCS regions by technology type. To preserve the daily or monthly adjustments to generator availability for certain categories (wind, solar, hybrid, hydropower, batteries, and other) by using the ITCS methods, the nameplate LTRA capacity was used. For all other categories (mostly thermal generators), summer and winter on-peak capacity contributions were used.

27. NERC, “Interregional Transfer Capability Study (ITCS).”

https://www.nerc.com/pa/RAPA/Documents/ITCS_Final_Report.pdf.

28. NERC, “2024 Long-Term Reliability Assessment,” December, 2024, 24.

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

29. Capacities are reported for both winter and summer seasonal ratings, along with nameplate values.

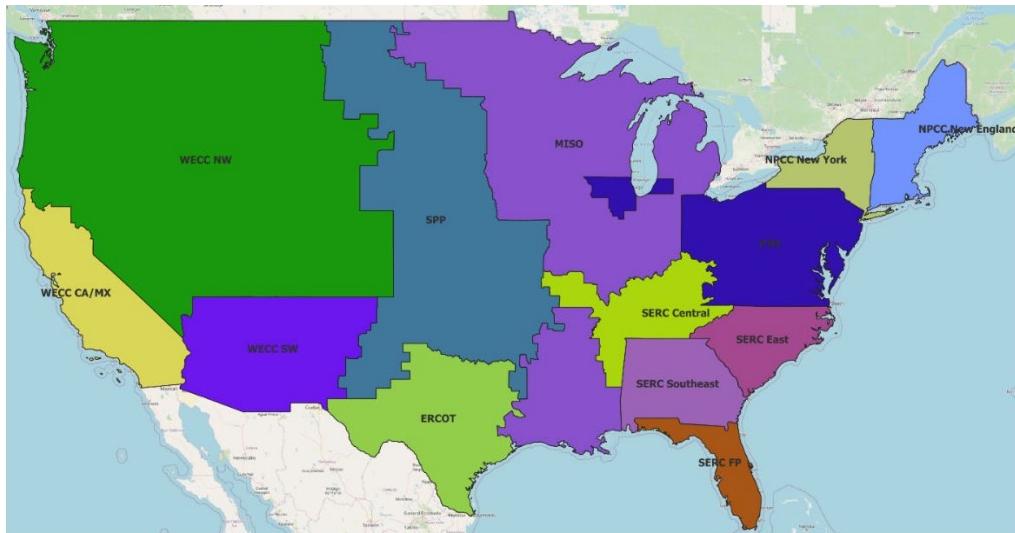


Figure A.1. NERC assessment areas.

To disaggregate generation capacity from the NERC assessment areas to the ITCS regions, EIA 860 plant-level data were used to tabulate the generation capacity for each ITCS region and NERC assessment area. The geographical boundaries for the NERC assessment areas and the ITCS regions were constructed based on ReEDS zones.³⁰ Disaggregation fractions were then calculated by technology type using the combined existing capacity and planned additions through 2030 from EIA 860 data as of December 2024. Specifically, to compute each fraction, an ITCS region's total (existing plus planned) capacity was divided by the corresponding total capacity across all ITCS regions within the same mapped NERC assessment area and fuel type group:

$$Fraction_{rf} = \frac{Capacity_{rf}}{\sum_{r \in ITCS(R)} Capacity_{r'f}} \quad (Equation.1)$$

Where $Capacity_{rf}$ is the capacity of fuel type f in ITCS region r and $ITCS(R)$ is the set of all ITCS regions mapped to the same NERC assessment area R . The denominator is the total capacity of that fuel type across all ITCS regions mapped to R .

Note that in cases where NERC assessment areas align one-to-one with ITCS regions, no mapping was required. Table A.1 summarizes which areas exhibited a direct one-to-one matching and which required disaggregation (1-to-many) or aggregation (many-to-one) to align with the ITCS regional structure.

An exception to this general approach is the case of the Front Range ITCS region, which geographically spans across two NERC assessment areas—WECC-NW and WECC-SW—resulting in two-to-one mapping. For this case, a separate allocation method was used: Plant-level data from EIA 860 were analyzed to determine the proportion of Front Range capacity located in each NERC area. These proportions were then used to derive custom weighting factors for allocating capacities from both WECC-NW and WECC-SW into the Front Range region.

30. NREL, "Regional Energy Development System," <https://www.nrel.gov/analysis/reeds/>.

Table A.1. Mapping of NERC assessment areas to ITCS regions.

NERC Area	ITCS Region	Match
ERCOT	ERCOT	1 to 1
NPCC-New England	NPCC-New England	1 to 1
NPCC-New York	NPCC-New York	1 to 1
SERC-C	SERC-C	1 to 1
SERC-E	SERC-E	1 to 1
SERC-FP	SERC-FP	1 to 1
SERC-SE	SERC-SE	1 to 1
WECC-SW	Southwest Region	1 to 1
MISO	MISO Central	
MISO	MISO East	
MISO	MISO South	1 to 4
MISO	MISO West	
SPP	SPP North	
SPP	SPP South	1 to 2
WECC-CAMX	Southern California	
WECC-CAMX	Northern California	1 to 2
WECC-NW	Oregon Region	
WECC-NW	Washington Region	1 to 3
WECC-NW	Wasatch Front	
WECC-NW	Front Range	
WECC-SW	Front Range	2 to 1

Table A.2 and Figure A.2 show the same combined capacities by ITCS region and NERC planning region, respectively.

Table A.2. Existing and Tier 1 capacities by NERC assessment area (in MW) in 2024.

2024 Existing + Tier 1		Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total		
EAST	Total	143,035	330,342	82,793	26,771	3,624	-	991	19,607	3,298	28,980	72,757	94,364	25,753	24,367	856,682		
	ISONE	Total	541	15,494	3,331	5,710	818	-	233	1,571	57	1,911	3,386	2,553	661	3,713	39,979	
	MISO	Total	37,914	64,194	11,127	2,867	613	-	329	4,396	1,031	2,533	29,777	41,715	7,775	3,049	207,319	
		MISO-W	12,651	13,608	2,753	1,491	244	-	2	-	200	777	7,368	29,411	2,367	741	71,612	
		MISO-C	15,050	10,307	2,169	494	32	-	152	773	499	769	10,587	7,350	2,026	1,774	51,982	
		MISO-S	5,493	31,052	5,100	589	243	-	117	49	5	845	8,024	596	2,109	291	54,511	
		MISO-E	4,720	9,227	1,105	292	94	-	57	3,574	327	143	3,799	4,359	1,273	243	29,213	
	NYISO	Total	-	22,937	3,330	2,631	334	-	-	1,400	60	4,915	1,039	2,706	860	5,710	45,924	
	PJM	Total	39,915	84,381	32,535	9,875	851	-	-	5,062	338	3,071	10,892	11,718	7,397	8,603	214,638	
		PJM-W	34,917	39,056	16,557	1,933	112	-	-	234	149	1,252	5,780	10,065	3,814	599	114,467	
		PJM-S	2,391	15,038	5,288	3,985	479	-	-	2,958	127	1,070	3,932	360	1,824	2,498	39,951	
		PJM-E	2,608	30,287	10,690	3,956	260	-	-	1,870	62	749	1,180	1,294	1,759	5,506	60,221	
	SERC	Total	45,747	113,334	31,702	4,063	989	-	83	6,701	768	11,425	26,959	982	7,707	3,221	253,680	
		SERC-C	13,348	20,127	8,280	148	36	-	-	1,784	100	4,995	2,308	982	1,851	20	53,978	
		SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	115	3,260	7,267	-	2,069	317	67,073	
		SERC-FL	4,346	47,002	3,502	1,957	310	-	83	-	538	-	10,121	-	2,804	2,051	72,714	
		SERC-E	14,777	16,340	11,902	1,044	219	-	-	3,369	15	3,170	7,263	-	983	833	59,914	
	SPP	Total	18,919	30,003	769	1,626	20	-	345	477	1,044	5,123	703	34,689	1,353	71	95,142	
		SPP-N	5,089	3,467	304	504	1	-	185	-	8	3,041	84	7,041	333	7	20,065	
		SPP-S	13,829	26,536	465	1,121	19	-	160	477	1,037	2,082	619	27,649	1,020	64	75,078	
ERCOT	Total	13,568	50,889	4,973	10	163	-	-	-	10,720	583	31,058	39,532	3,464	2,531	157,490		
ERCOT	Total	13,568	50,889	4,973	10	163	-	-	-	10,720	583	31,058	39,532	3,464	2,531	157,490		
WEST	Total	21,666	87,403	9,403	829	1,565	4,093	106	4,536	15,238	52,687	44,042	35,071	1,944	16,271	294,854		
	CAISO+	Total	1,816	37,434	5,582	185	726	2,004	35	3,514	11,156	10,211	25,614	7,773	829	10,047	116,925	
		CALI-N	-	12,942	5,582	165	465	1,049	9	1,967	2,672	8,727	6,723	1,373	349	5,036	47,059	
		CALI-S	1,816	24,492	-	20	261	955	26	1,547	8,484	1,483	18,891	6,400	480	5,011	69,866	
	Non-CA	Total	19,850	49,969	3,820	644	839	2,089	71	1,022	4,082	42,476	18,428	27,298	1,115	6,224	177,929	
	WECC		WA	560	3,919	1,096	17	352	-	-	140	350	24,402	1,052	2,690	243	386	35,207
		OR	-	3,915	-	6	293	21	-	-	482	8,253	2,145	3,440	141	372	19,068	
		SOUTHWEST	4,842	17,985	2,724	323	102	1,047	-	176	2,173	1,019	5,641	3,685	168	2,452	42,335	
		WASATCH	7,033	14,061	-	87	56	1,011	61	444	750	7,587	5,625	4,052	305	1,674	42,746	
		FRONT R	7,415	10,089	-	211	36	10	10	262	328	1,215	3,966	13,432	258	1,340	38,572	
		Total	178,268	468,635	97,169	27,610	5,353	4,093	1,096	24,144	29,256	82,249	147,856	168,966	31,161	43,169	1,309,026	

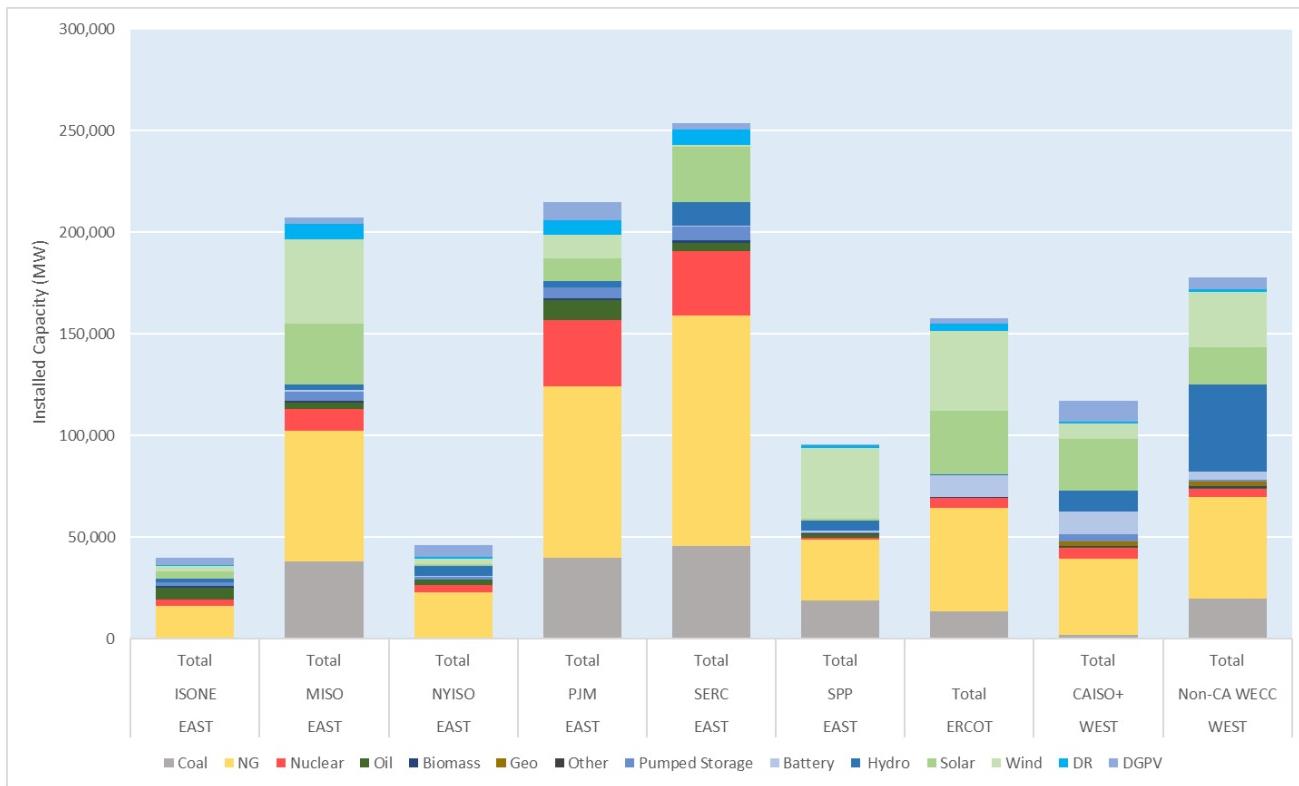


Figure A.2. Existing and Tier 1 capacities by NERC assessment area in 2024.

Forecasting 2030 Resource Mixes

To develop the 2030 ITCS generation portfolio, the study team added new capacity builds and removed planned retirements.

- (i) *Tier 1:* Assumes that only projects considered very mature in the development pipeline—such as those with signed interconnection agreements—will be built. This results in minimal capacity additions beyond 2026. The data are based on projects designated as Tier 1 in the 2024 LTRA data for the year 2030.

Retirements

To project which units will retire by 2030, the study team primarily used the LTRA 2024 data and cross-checked it with EIA data. The assessment areas were disaggregated to ITCS zones based on the ratios of projected retirements in EIA 860 data. The three scenarios modeled are as follows:

- (i) *Announced:* Assumes that in addition to confirmed retirements, generators that have publicly announced retirement plans but have not formally notified system operators have also begun the retirement process. This is based on data from the 2024 LTRA, which were collected by the NERC team from sources like news announcements, public disclosures, etc.

- (ii) *None*: Assumes that there are no retirements between 2024 and 2030 for comparison. Delaying or canceling some near-term retirements may not be feasible, but this case can help determine how much retirements contribute to resource adequacy challenges in regions where rapid AI and data center growth is expected.

Generation Stack for Each Scenario

Finally, when summing all potential future changes, the team arrived at a generation stack for each of the various scenarios to be studied. The first figure provides a visual comparison of all the cases, which vary from 1,309 GW to 1,519 GW total generation capacity for the entire continental United States, to enable the exploration of a range of potential generation futures. The tables below provide breakdowns by ITCS region and by resource type.

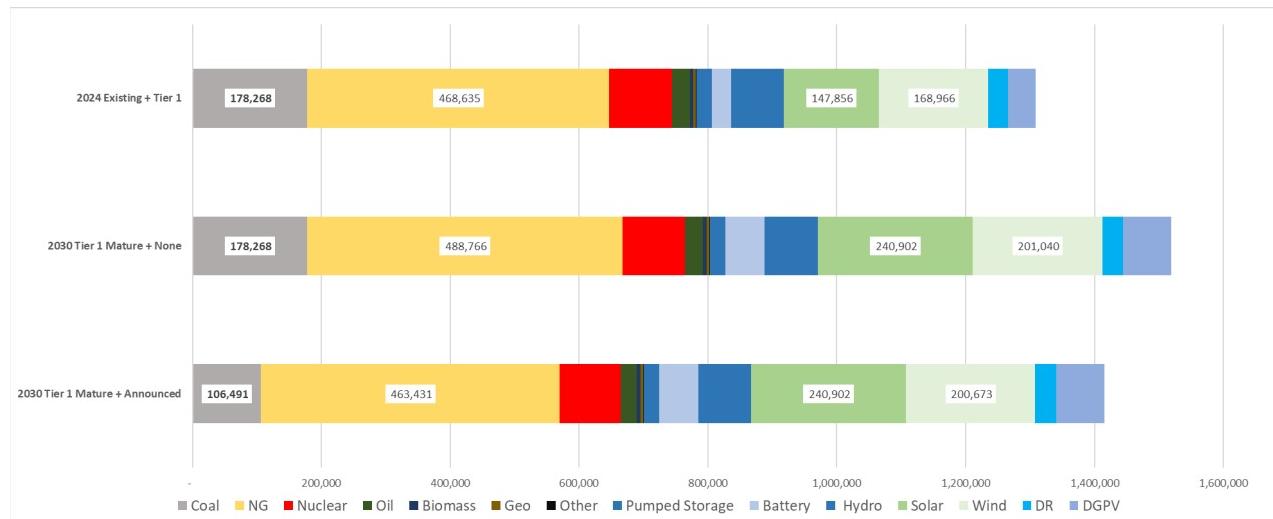


Figure A.9. Comparison of 2030 generation stacks for the various scenarios.

Table A.4. 2030 generation stack for Tier 1 mature + announced retirements.

2030 Tier 1 Mature + Announced		Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	Total	84,730	328,457	82,793	24,272	3,473	-	991	19,591	12,415	28,897	126,849	113,568	26,837	36,768	889,641
ISONE	Total	7	13,708	3,331	5,687	741	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	42,845
MISO	Total	13,001	60,132	11,127	2,873	473	-	329	4,380	2,960	2,450	44,132	43,369	7,775	3,049	196,049
	MISO-W	4,338	12,747	2,753	1,494	188	-	2	-	574	751	10,920	30,577	2,367	741	67,453
	MISO-C	5,161	9,655	2,169	495	25	-	152	770	1,433	743	15,690	7,642	2,026	1,774	47,735
	MISO-S	1,883	29,087	5,100	591	187	-	117	49	14	817	11,892	619	2,109	291	52,756
	MISO-E	1,619	8,643	1,105	293	72	-	57	3,561	938	138	5,630	4,531	1,273	243	28,105
NYISO	Total	-	21,907	3,330	2,628	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	50,396
PJM	Total	26,662	87,228	32,535	8,117	917	-	-	5,062	2,276	3,071	33,530	18,807	7,638	10,955	236,798
	PJM-W	23,323	40,373	16,557	1,589	120	-	-	234	1,004	1,252	17,793	16,153	3,939	762	123,100
	PJM-S	1,597	15,546	5,288	3,276	516	-	-	2,958	853	1,070	12,105	577	1,883	3,181	48,850
	PJM-E	1,742	31,309	10,690	3,252	280	-	-	1,870	419	749	3,632	2,076	1,816	7,012	64,848
SERC	Total	31,672	116,117	31,702	3,391	989	-	83	6,701	3,021	11,425	38,360	982	8,088	7,893	260,423
	SERC-C	8,883	23,777	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	54,014
	SERC-SE	10,321	28,127	8,018	899	424	-	-	1,548	618	3,260	9,024	-	2,213	317	64,768
	SERC-FL	2,851	47,092	3,502	1,477	310	-	83	-	2,208	-	16,717	-	3,022	5,865	83,127
	SERC-E	9,617	17,122	11,902	868	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	58,513
SPP	Total	13,389	29,365	769	1,576	20	-	345	477	2,434	5,123	5,991	41,755	1,815	71	103,130
	SPP-N	3,602	3,394	304	489	1	-	185	-	18	3,041	717	8,475	447	7	20,679
	SPP-S	9,787	25,971	465	1,087	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	82,451
ERCOT	Total	11,568	49,436	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	208,894
ERCOT	Total	11,568	49,436	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	208,894
WEST	Total	10,193	85,538	7,103	823	1,427	3,983	106	4,366	21,330	52,060	51,648	43,935	1,981	31,931	316,424
CAISO+	Total	16	35,789	3,282	185	726	2,059	35	3,514	14,316	10,211	27,112	7,773	866	17,055	122,938
	CALI-N	-	12,373	3,282	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	48,897
	CALI-S	16	23,416	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	74,041
Non-CA	Total	10,177	49,749	3,820	639	701	1,924	71	852	7,014	41,849	24,536	36,162	1,115	14,876	193,485
WECC	WA	243	3,971	1,096	16	286	-	-	111	459	24,033	1,404	3,631	243	1,092	36,588
	OR	-	3,967	-	6	238	18	-	-	632	8,128	2,865	4,644	141	1,051	21,689
	SOUTHWEST	3,657	17,343	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	47,022
	WASATCH	3,055	14,247	-	86	45	850	61	355	983	7,472	7,512	5,470	305	4,733	45,175
	FRONT R	3,221	10,222	-	208	30	8	10	209	430	1,197	5,296	18,133	258	3,789	43,011
	Total	106,491	463,431	94,869	25,106	5,063	3,983	1,096	23,958	61,003	81,539	240,902	200,673	32,282	74,563	1,414,959

Table A.5. 2030 generation stack for Tier 1 mature + no retirements.

2030 Tier 1 Mature + No Retirements		Coal	NG	Nuclear	Oil	Biomass	Geo	Other	Pumped Storage	Battery	Hydro	Solar	Wind	DR	DGPV	Total
EAST	Total	143,035	345,459	82,793	27,336	3,701	-	991	19,607	12,415	28,980	126,849	113,840	26,837	36,768	968,610
ISONE	Total	541	15,584	3,331	5,891	818	-	233	1,571	1,664	1,911	3,676	4,048	661	5,606	45,534
MISO	Total	37,914	66,729	11,127	3,197	613	-	329	4,396	2,960	2,533	44,132	43,641	7,775	3,049	228,393
	MISO-W	12,651	14,145	2,753	1,662	244	-	2	-	574	777	10,920	30,768	2,367	741	77,605
	MISO-C	15,050	10,714	2,169	551	32	-	152	773	1,433	769	15,690	7,690	2,026	1,774	58,823
	MISO-S	5,493	32,278	5,100	657	243	-	117	49	14	845	11,892	623	2,109	291	59,710
	MISO-E	4,720	9,592	1,105	326	94	-	57	3,574	938	143	5,630	4,560	1,273	243	32,255
NYISO	Total	-	22,937	3,330	2,646	334	-	-	1,400	60	4,915	1,159	4,608	860	9,194	51,444
PJM	Total	39,915	88,880	32,535	9,907	928	-	-	5,062	2,276	3,071	33,530	18,807	7,638	10,955	253,504
	PJM-W	34,917	41,138	16,557	1,939	122	-	-	234	1,004	1,252	17,793	16,153	3,939	762	135,810
	PJM-S	2,391	15,840	5,288	3,998	522	-	-	2,958	853	1,070	12,105	577	1,883	3,181	50,667
	PJM-E	2,608	31,902	10,690	3,969	284	-	-	1,870	419	749	3,632	2,076	1,816	7,012	67,027
SERC	Total	45,747	120,232	31,702	4,063	989	-	83	6,701	3,021	11,425	38,360	982	8,088	7,893	279,285
	SERC-C	13,348	24,958	8,280	148	36	-	-	1,784	180	4,995	3,070	982	1,851	29	59,660
	SERC-SE	13,275	29,866	8,018	915	424	-	-	1,548	618	3,260	9,024	-	2,213	317	69,478
	SERC-FL	4,346	48,163	3,502	1,957	310	-	83	-	2,208	-	16,717	-	3,022	5,865	86,173
	SERC-E	14,777	17,246	11,902	1,044	219	-	-	3,369	15	3,170	9,549	-	1,002	1,682	63,973
SPP	Total	18,919	31,098	769	1,632	20	-	345	477	2,434	5,123	5,991	41,755	1,815	71	110,449
	SPP-N	5,089	3,594	304	506	1	-	185	-	18	3,041	717	8,475	447	7	22,385
	SPP-S	13,829	27,504	465	1,126	19	-	160	477	2,416	2,082	5,274	33,280	1,368	64	88,064
ERCOT	Total	13,568	51,458	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	212,916
ERCOT	Total	13,568	51,458	4,973	10	163	-	-	-	27,258	583	62,406	43,169	3,464	5,864	212,916
WEST	Total	21,666	91,849	9,403	829	1,565	4,156	106	4,536	21,330	52,687	51,648	44,030	1,981	31,931	337,717
CAISO+	Total	1,816	39,560	5,582	185	726	2,059	35	3,514	14,316	10,211	27,112	7,773	866	17,055	130,809
	CALI-N	-	13,677	5,582	165	465	1,078	9	1,967	3,429	8,727	7,116	1,373	364	8,549	52,501
	CALI-S	1,816	25,883	-	20	261	982	26	1,547	10,887	1,483	19,996	6,400	501	8,506	78,308
Non-CA	Total	19,850	52,289	3,820	645	839	2,097	71	1,022	7,014	42,476	24,536	36,257	1,115	14,876	206,908
WECC	WA	560	4,166	1,096	17	352	-	-	140	459	24,402	1,404	3,642	243	1,092	37,573
	OR	-	4,161	-	6	293	22	-	-	632	8,253	2,865	4,658	141	1,051	22,081
	SOUTHWEST	4,842	18,294	2,724	323	102	1,047	-	176	4,511	1,019	7,460	4,284	168	4,211	49,158
	WASATCH	7,033	14,945	-	88	56	1,018	61	444	983	7,587	7,512	5,486	305	4,733	50,251
	FRONT R	7,415	10,723	-	212	36	10	10	262	430	1,215	5,296	18,187	258	3,789	47,844
	Total	178,268	488,766	97,169	28,175	5,429	4,156	1,096	24,144	61,003	82,249	240,902	201,040	32,282	74,563	1,519,243

Appendix B - Representing Canadian Transfer Limits

Introduction

The reliability and stability of cross-border electricity interconnections between the United States and Canada are critical to ensuring continuous power delivery amid evolving demands and variable supply conditions. In recent years, increased integration of wind and solar generation, coupled with extreme weather events, has introduced significant uncertainties in regional power flows.

This report describes the development and implementation of a machine learning (ML)-based model designed to project the maximum daily energy transfer (MaxFlow) across major United States–Canada interfaces, such as BPA–BC Hydro and NYISO–Ontario. Leveraging 15 years of high-resolution load and generation data, summarizing it into key daily statistics, and training a robust eXtreme Gradient Boosting (XGBoost) regressor can allow data-driven predictions to be captured with quantified uncertainty.

The project team provided percentile-based forecasts—25, 50, and 75 percent—to support both conservative and strategic planning. The conservative methodology (25 percent) was used for this report to ensure availability when needed.

The subsequent sections detail the methodology used for data processing and feature engineering, the architecture and training of the predictive model, and the validation metrics and feature importance analyses used. Future enhancements could include incorporating weather patterns, neighboring-region dynamics, and fuel-specific generation profiles to further strengthen predictive performance and support grid resilience.

Methodology

This section describes the ML approach used to build the MaxFlow prediction model.

Dataset Collection and Preparation

Data were collected for hourly and derived daily load and generation over a 15-year period (2010–2024), comprising 8,760 hourly observations annually. Hourly interconnection flow rates were collected for the same years across all major United States–Canada interfaces.^{1–17}

Underlying Hypothesis

The team hypothesized that the MaxFlow between interconnected regions is critically influenced by regional load and generation extrema (maximum and minimum) and their variability. These statistics reflect grid stress conditions, influencing interregional energy flow. Additionally, nonlinear interactions due to imbalances in adjacent regions further affect energy transfer dynamics.

Regression Model

The XGBoost regression model was chosen because of its ability to capture complex, nonlinear relationships, regularization capability to prevent overfitting, high speed and performance, fast convergence, built-in handling of missing data, and ease of confidence interval approximation.

XGBoost builds many small decision trees, one after another. Each new tree learns to correct the mistakes of the previous ensemble by focusing on which predictions had the greatest error. Instead of creating one large, complex tree, it combines many simpler trees—each making a modest adjustment—so that, together, they capture nonlinear patterns and interactions. Regularization (penalties for tree size and leaf adjustments) prevents overfitting, and a “learning rate” scales each tree’s contribution so that improvements are made gradually. The final prediction is simply the sum of all those small corrections.

Model Training, Validation, and Assessment

Figure B.1 shows the data analysis and prediction process, which ties together seven stages—from raw CSV loading through outlier filtering, feature engineering, projecting to 2030, rebuilding 2030 features, training an XGBoost model, and finally making and evaluating the 2030 flow forecasts with quantiles. Each stage feeds into the next, ensuring that the features used for training mirror exactly those that will be available for future (2030) predictions.

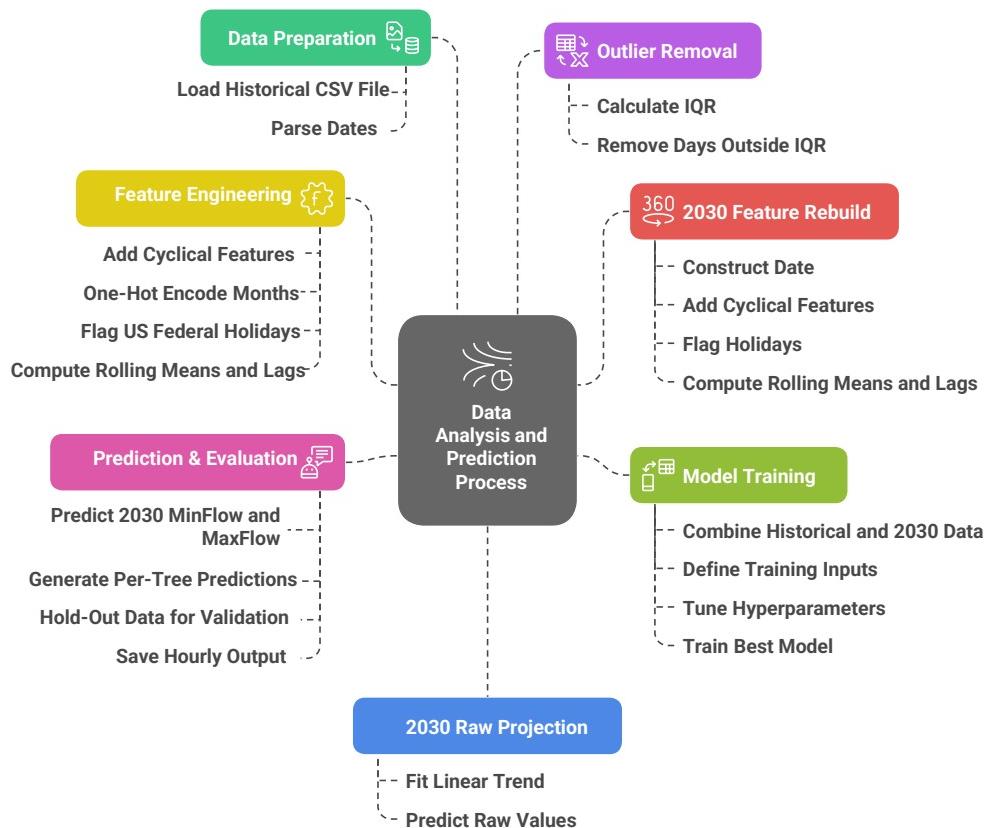


Figure B.1. Data analysis and prediction process.

Example Feature Importance for Predicting MaxFlow from Ontario to NYISO

The trained ML/XGBoost model can be used for predicting the desired year’s MaxFlow. In addition, feature importance analysis can be added to assess the contribution of each variable.

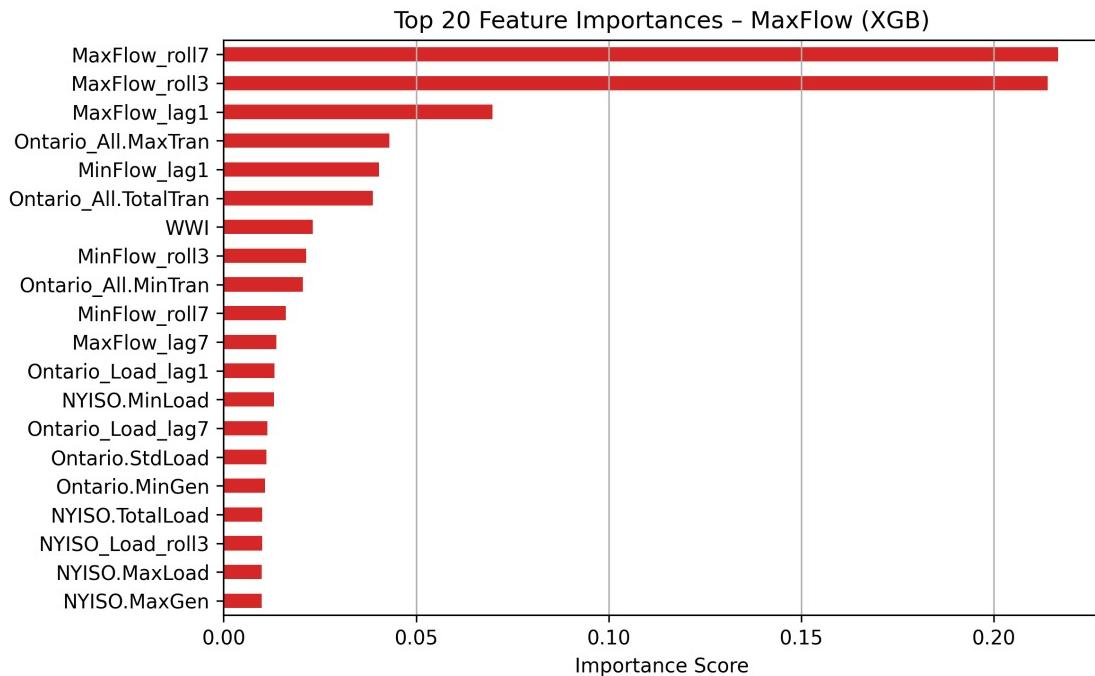


Figure B.2. Feature importance for predicting the hourly maximum energy transfer (MaxFlow) between NYISO and Ontario. XGB = eXtreme Gradient Boosting.

The feature importance plot shows that MaxFlow rolling/lagging features and Ontario_All.MaxTran are the dominant predictors of MaxFlow, meaning temporal patterns and Ontario's peak transfer capacity strongly influence interregional flow limits. Weather-related variables (WWI, e.g., temperature, humidity, etc.) and Ontario_All.TotalTran also rank highly. The 2030 MaxFlow prediction plot shows seasonal fluctuations, with higher values early and late in the year. The red shaded area represents a 95 percent confidence interval for the predictions.

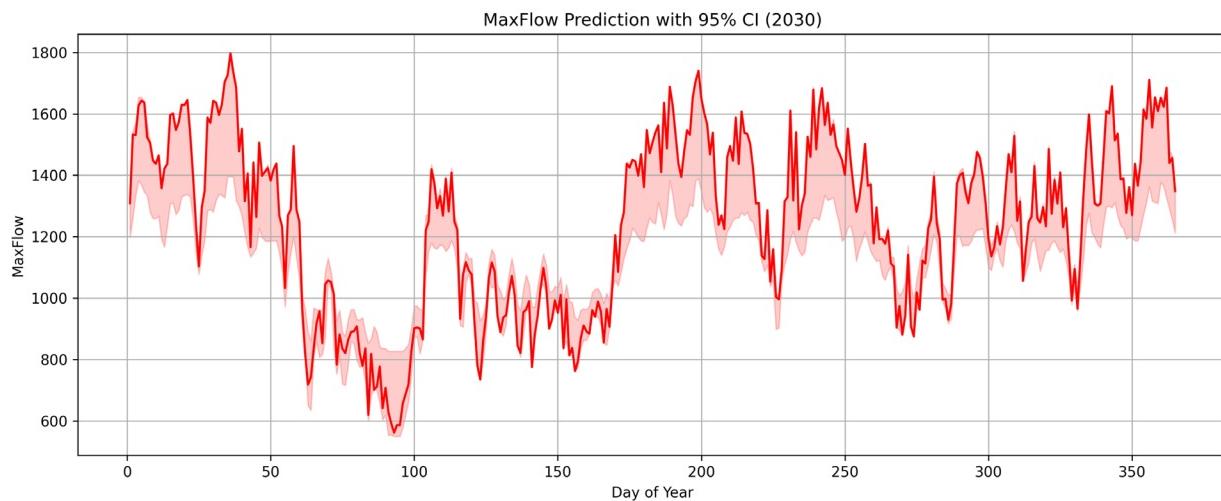


Figure B.3. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI).

Model Performance

Validating model performance on unseen data is essential to ensure the model's reliability and generalizability. The following evaluation examines how well the XGBoost model predicts minimum energy transfer (MinFlow) and MaxFlow on the validation split, highlighting strengths and areas for improvement.

Rigorous performance evaluation is a fundamental step in any ML workflow. From quantifying error metrics (root mean square error and mean absolute error) and goodness-of-fit (R^2) on both training and validation splits, it is possible to identify overfitting, assess generalization, and guide model refinement. Table B.1 shows XGBoost model performance for the Ontario–NYISO transfer limit.

Table B.1. eXtreme Gradient Boosting model performance for the Ontario–NYISO transfer limit.

Metric	Value	Explanation
MinFlow RMSE (Train)	69.2528	Root mean square error (RMSE) on training data for minimum energy transfer (MinFlow)
MinFlow R^2 (Train)	0.9651	R^2 on training data for MinFlow (higher → better fit)
MinFlow RMSE (Validation)	163.6642	RMSE on held-out data for MinFlow
MinFlow R^2 (Validation)	0.8073	R^2 on held-out data for MinFlow (higher → better generalization)
MaxFlow RMSE (Train)	114.4234	RMSE on training data for maximum energy transfer (MaxFlow)
MaxFlow R^2 (Train)	0.8838	R^2 on training data for MaxFlow (higher → better fit)
MaxFlow RMSE (Validation)	144.9614	RMSE on held-out data for MaxFlow
MaxFlow R^2 (Validation)	0.8178	R^2 on held-out data for MaxFlow (higher → better generalization)

Overall, the XGBoost model delivers excellent in-sample as well as out-of-sample accuracy. Similar outputs are available for each transfer limit.

Maximum flow predictions: Ontario to New York

Ontario and NYISO are connected through multiple high-voltage interconnections, which collectively provide a total transfer capability of up to 2,500 MW, subject to individual tie-line limits. Table B.2 outlines the data sources, preparation process, and assumptions used in creating datasets for the prediction models.

Table B.2. Ontario to New York transmission flow data and assumptions overview.

Description	
Data source	https://www.ieso.ca/power-data/data-directory
Data preparation	IESO public hourly inter-tie schedule flow data can be accessed for the years spanning from 2002 to 2023.
Assumptions	Positive flow indicates that Ontario is exporting to NY, and negative flow indicates that Ontario is importing from NY.

Figure B.4 illustrates the historical monthly MaxFlow for Ontario from 2007 through 2024, alongside 2030 projected quartile scenarios (Q1, Q2, and Q3). Analyzing these trends helps assess future reliability and facilitates capacity planning under varying conditions.

Historical monthly peaks (2007–2023) reveal a clear seasonal cycle for ONT–NYISO transfers: flows typically increase in late winter/early spring (February–April) and again in late fall/early winter (November–December). Over 16 years, the average spring peaks hovered around 1,700–1,900 MW, with occasional spikes above 2,200 MW. The 2030 forecast for Q1, Q2, and Q3 aligns with this pattern, predicting a springtime peak near 1,800 MW, a summer trough around 1,400 MW, and a modest late-summer uptick near 1,500 MW.

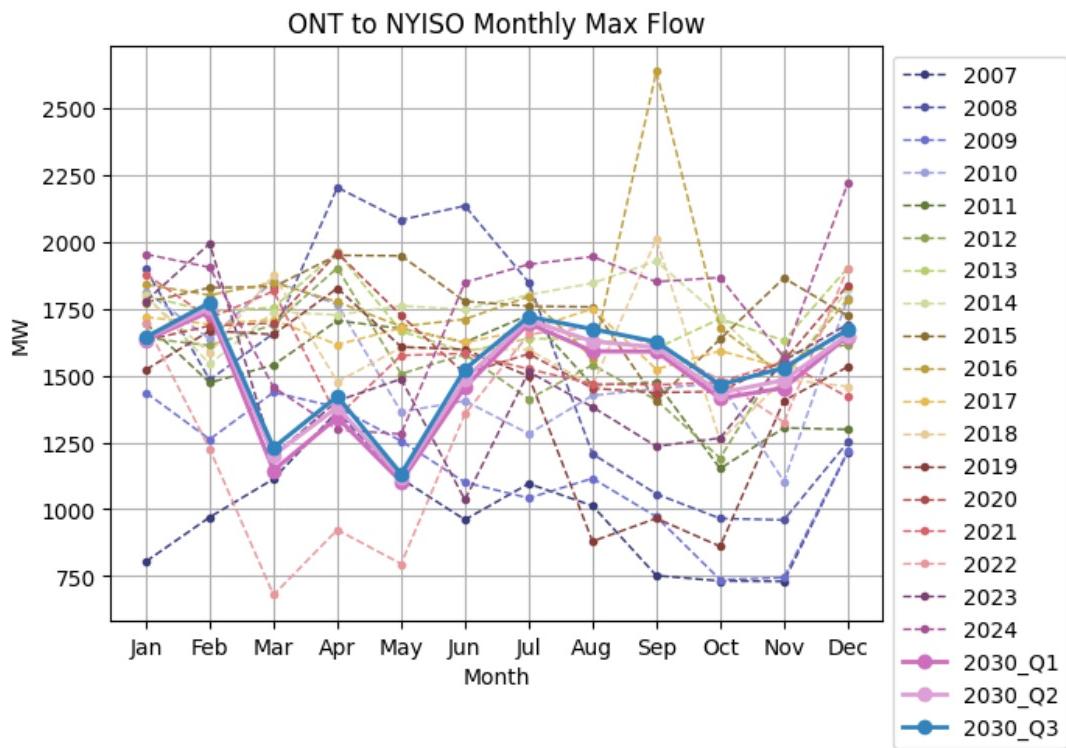


Figure B.4. Monthly maximum energy transfer between Ontario (ONT) and New York (NYISO).

The team used robust validation metrics to justify these results. When trained on daily data from the 2010–2024 period—incorporating projected 2030 loads, seasonal flags, and holiday effects—the XGBoost model achieved $R^2 > 0.80$ and a root mean square error below 150 MW on an unseen 20 percent hold-out dataset. Moreover, the 95 percent confidence intervals for monthly maxima were narrow (approximately ± 150 MW), demonstrating low predictive uncertainty. A comparison of predicted maxima with historical extremes revealed that 2030 forecasts consistently fell within (or slightly above) the previous window of variability, implying realistic demand-driven behavior. In summary, the close alignment with historical peaks, strong cross-validated performance, and tight confidence bands collectively validate the results.

Discussion

The reason that the team used ML/XGBoost to approximate the 2030 transfer profiles was to ensure that there would be no violations or inconsistencies between transfer limits, load, and generation. The 15 years of data used were sufficient for having the models learn historical relationships and project them forward to 2030 to capture the underlying trends in load,

generation, and their interactions. The use of such an extensive dataset justifies using ML to establish consistent transfer profiles.

However, in some regions, like Ontario to NYISO, the available data encompassed a shorter time period, and the relationships were only partially captured because of a lack of neighboring-region data. In such cases, it was necessary to incorporate additional predictors, such as rolling and lag features from the transfer limits. Although the direct use of transfer limit data to project future transfer limits would typically be avoided, these engineered features help improve predictions when data coverage is sparse and the model's goodness-of-fit is low.

In all cases, the ML models ensured that these historical relationships were not violated, maintaining internal consistency among load, generation, and transfer limits. Overall, the team relied on ML when long-term data were available for training and projecting load and generation profiles. Rolling and lag features were used to reinforce the model when data availability was limited, but always with the goal of upholding consistent physical relationships in the 2030 projections.

Supplementary Plots for Additional Transfers

This section presents figures and tables showing results and source data information for each transfer listed below:

- (iii) Pacific Northwest to British Columbia
- (iv) Alberta to Montana
- (v) Manitoba to MISO West
- (vi) Ontario to MISO West
- (vii) Ontario to MISO East
- (viii) Ontario to New York
- (ix) Hydro-Quebec to New York
- (x) Hydro-Quebec to New England
- (xi) New Brunswick to New England

The figures show the daily MaxFlow for each transfer that was considered in this analysis.

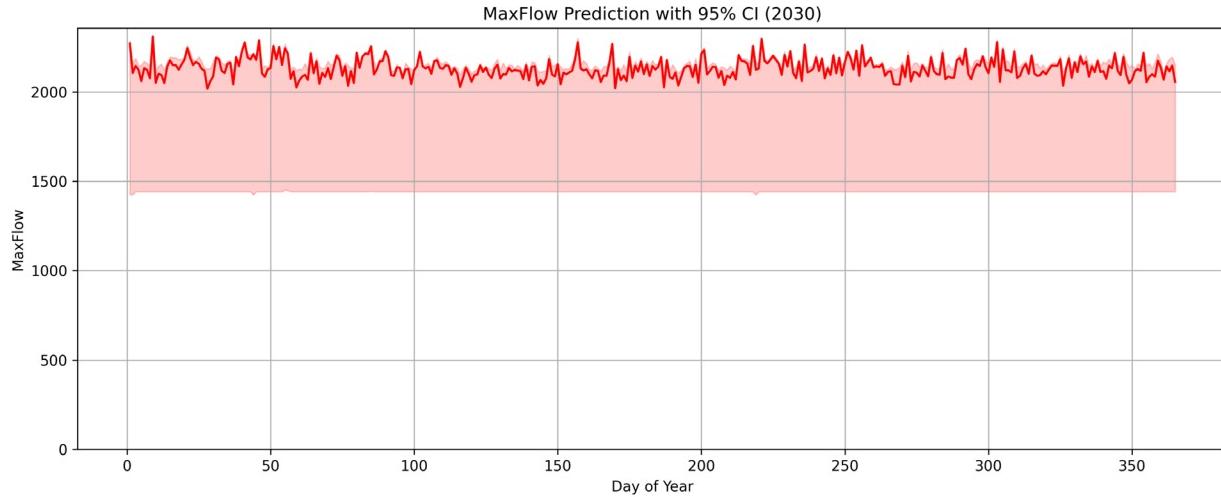


Figure B.5. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between British Columbia and the Pacific Northwest.

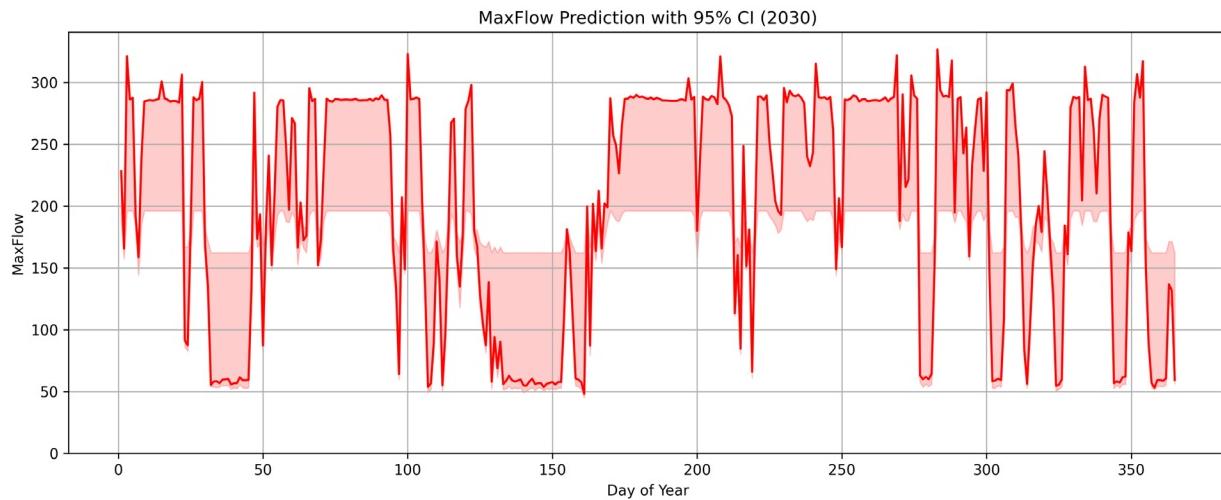


Figure B.6. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between AESO and Montana.

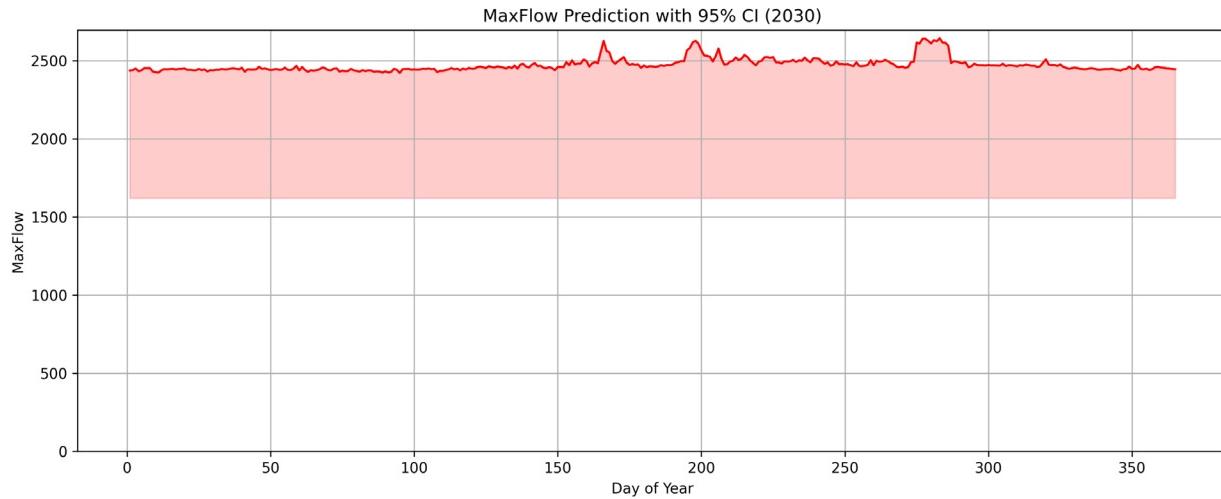


Figure B.7. Projected 2030 maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Manitoba and MISO.

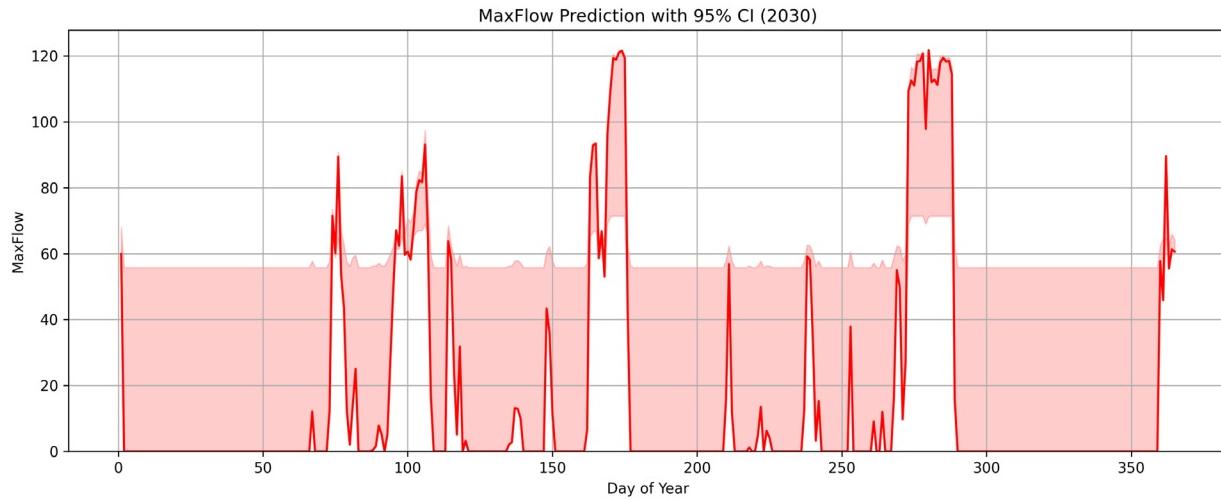


Figure B.8. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO West.

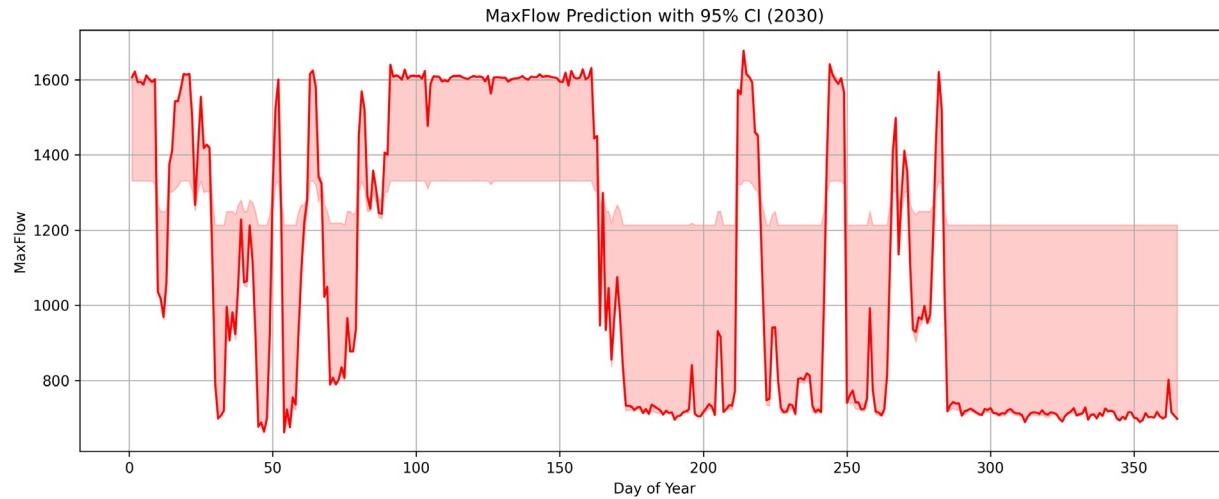


Figure B.9. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and MISO East.

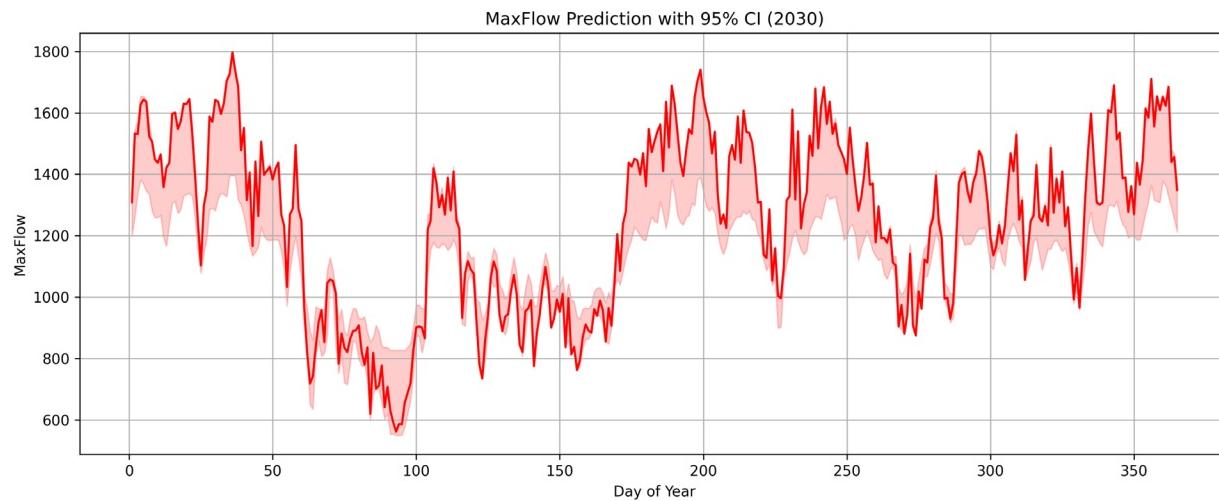


Figure B.10. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Ontario and New York.

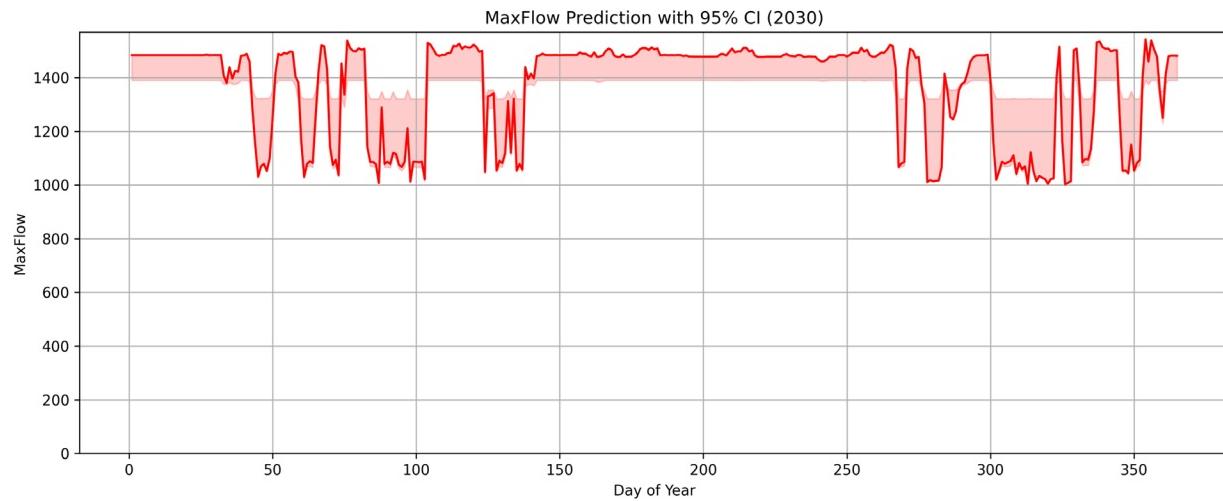


Figure B.11. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New York.

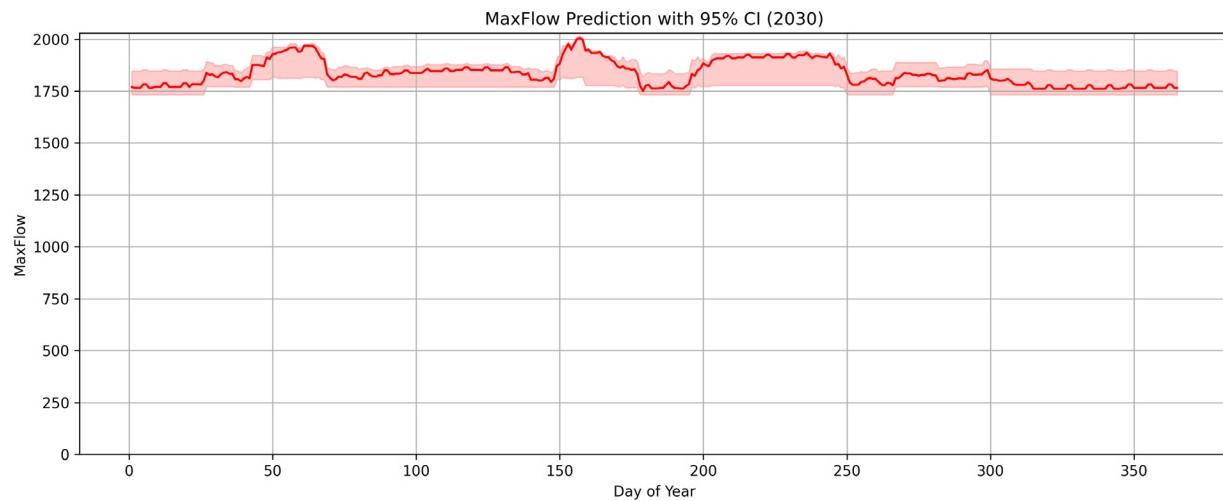


Figure B.12. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between Quebec and New England.

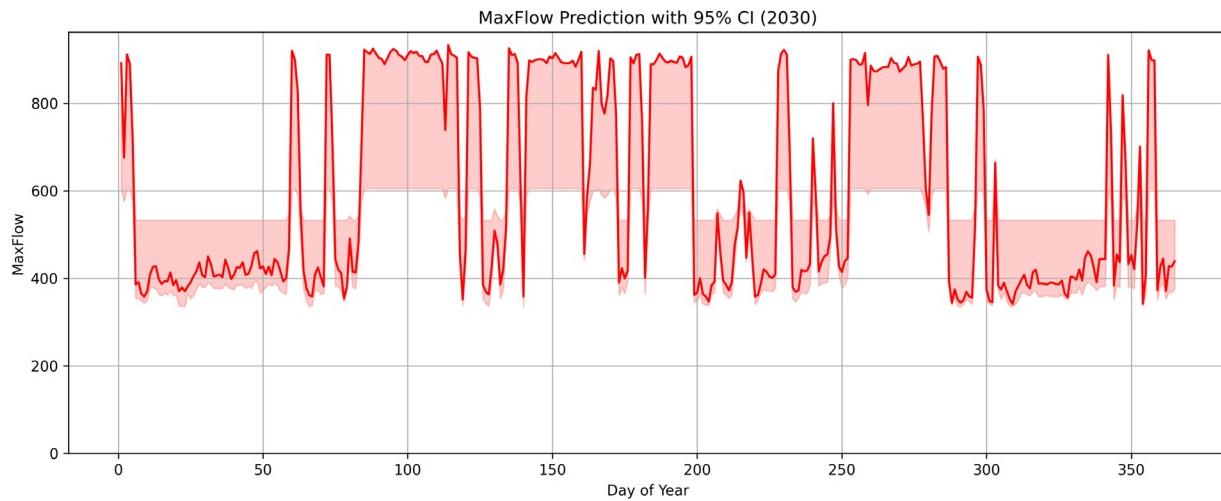


Figure B.13. Projected 2030 daily maximum energy transfer (MaxFlow) with 95 percent confidence interval (CI) between New Brunswick and New England.

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EO 14262



Federal Register / Vol. 90, No. 70 / Monday, April 14, 2025 / Presidential Documents

15521

Presidential Documents

Executive Order 14262 of April 8, 2025

Strengthening the Reliability and Security of the United States Electric Grid

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered:

Section 1. Purpose. The United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and an increase in domestic manufacturing. This increase in demand, coupled with existing capacity challenges, places a significant strain on our Nation's electric grid. Lack of reliability in the electric grid puts the national and economic security of the American people at risk. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy from all available electric generation sources and the integrity of our Nation's electric grid.

Sec. 2. Policy. It is the policy of the United States to ensure the reliability, resilience, and security of the electric power grid. It is further the policy of the United States that in order to ensure adequate and reliable electric generation in America, to meet growing electricity demand, and to address the national emergency declared pursuant to Executive Order 14156 of January 20, 2025 (Declaring a National Energy Emergency), our electric grid must utilize all available power generation resources, particularly those secure, redundant fuel supplies that are capable of extended operations.

Sec. 3. Addressing Energy Reliability and Security with Emergency Authority. (a) To safeguard the reliability and security of the United States' electric grid during periods when the relevant grid operator forecasts a temporary interruption of electricity supply is necessary to prevent a complete grid failure, the Secretary of Energy, in consultation with such executive department and agency heads as the Secretary of Energy deems appropriate, shall, to the maximum extent permitted by law, streamline, systemize, and expedite the Department of Energy's processes for issuing orders under section 202(c) of the Federal Power Act during the periods of grid operations described above, including the review and approval of applications by electric generation resources seeking to operate at maximum capacity.

(b) Within 30 days of the date of this order, the Secretary of Energy shall develop a uniform methodology for analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy. This methodology shall:

- (i) analyze sufficiently varied grid conditions and operating scenarios based on historic events to adequately inform the methodology;
- (ii) accredit generation resources in such conditions and scenarios based on historical performance of each specific generation resource type in the real time conditions and operating scenarios of each grid scenario; and
- (iii) be published, along with any analysis it produces, on the Department of Energy's website within 90 days of the date of this order.

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(c) The Secretary of Energy shall establish a process by which the methodology described in subsection (b) of this section, and any analysis and results it produces, are assessed on a regular basis, and a protocol to identify which generation resources within a region are critical to system reliability. This protocol shall additionally:

(i) include all mechanisms available under applicable law, including section 202(c) of the Federal Power Act, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region; and

(ii) prevent, as the Secretary of Energy deems appropriate and consistent with applicable law, including section 202 of the Federal Power Act, an identified generation resource in excess of 50 megawatts of nameplate capacity from leaving the bulk-power system or converting the source of fuel of such generation resource if such conversion would result in a net reduction in accredited generating capacity, as determined by the reserve margin methodology developed under subsection (b) of this section.

Sec. 4. General Provisions. (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



THE WHITE HOUSE,
April 8, 2025.

[FR Doc. 2025-06381
Filed 4-11-25; 8:45 am]
Billing code 3395-F4-P

Available at (accessed on 5/27/2025):

<https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid>



**U.S. DEPARTMENT
of ENERGY**

For more information, visit:
energy.gov/topics/reliability

DOE/Publication Number • July, 7 2025

EXHIBIT E



Global Monitoring Laboratory

Trends in CO₂, CH₄, N₂O, SF₆

[Trends in CO₂](#)[Trends in CH₄](#)[Trends in N₂O](#)[Trends in SF₆](#)

Trends in Atmospheric Carbon Dioxide (CO₂)

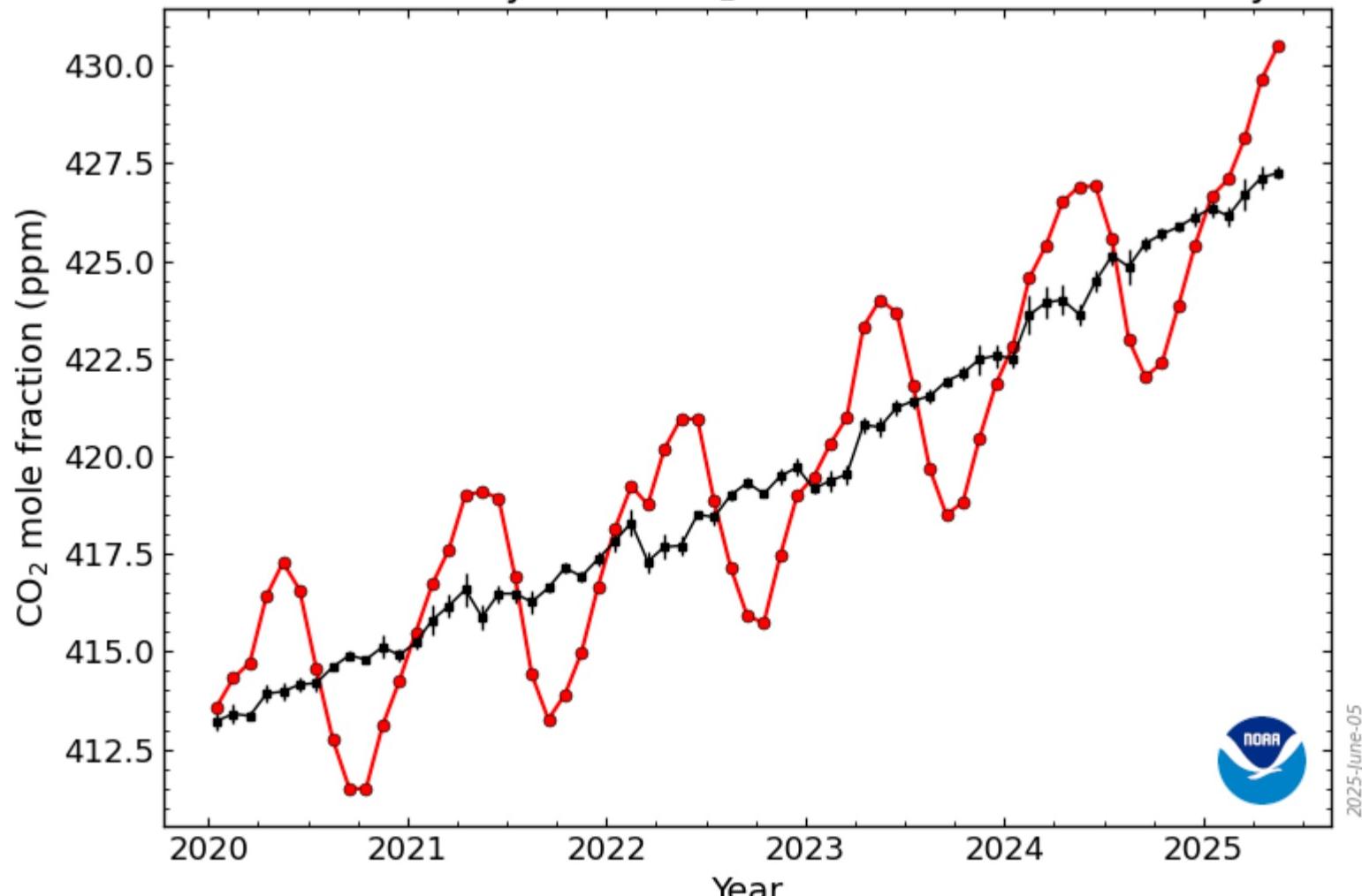
[Mauna Loa, Hawaii](#)[Global](#)[CO₂ Animation](#)[CO₂ Emissions](#)[Last Month](#)[Last 1 Year](#)[Full Record](#)[Growth Rate](#)[Data](#)[Interactive Plots](#)

Monthly Average Mauna Loa CO₂

May 2025: 430.51 ppm
 May 2024: 426.90 ppm

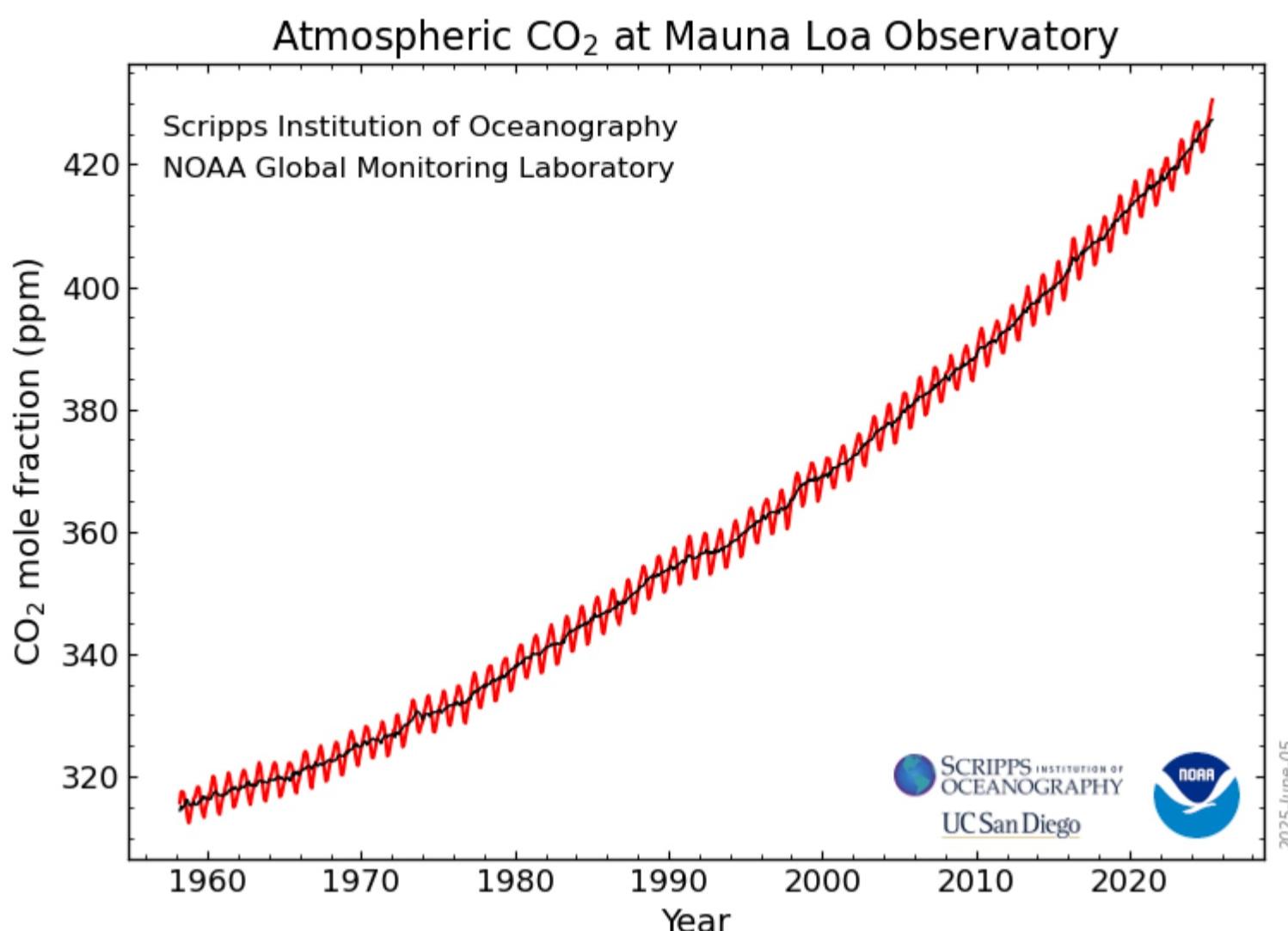
Last updated: Jun 05, 2025

Recent Monthly Mean CO₂ at Mauna Loa Observatory



2025-June-05

[PNG Version](#) [PDF Version](#)



[PNG Version](#) [PDF Version](#)

The graphs show monthly mean carbon dioxide measured at Mauna Loa Observatory, Hawaii. The carbon dioxide data on Mauna Loa constitute the longest record of direct measurements of CO₂ in the atmosphere. They were started by C. David Keeling of the Scripps Institution of Oceanography in March of 1958 at a facility of the National Oceanic and Atmospheric Administration [Keeling, 1976]. NOAA started its own CO₂ measurements in May of 1974, and they have run in parallel with those made by Scripps since then [Thoning, 1989].

The last five complete years of the Mauna Loa CO₂ record plus the current year are shown in the first graph. The full record of combined Scripps data and NOAA data is shown in the second graph. Every monthly mean is the average of daily means, which are in turn based on hourly averages, but only for those hours during which "background" conditions prevail (see gml.noaa.gov/ccgg/about/co2_measurements.html for more information).

The **red** lines and symbols represent the monthly mean values, centered on the middle of each month. The **black** lines and symbols represent the same, after correction for the average seasonal cycle. The latter is determined as a moving average of SEVEN adjacent seasonal cycles centered on the month to be corrected, except for the first and last THREE and one-half years of the record, where the seasonal cycle has been averaged over the first and last SEVEN years, respectively.

The vertical bars on the **black** lines of the first graph show the uncertainty of each monthly mean based on the observed variability of CO₂ in different weather systems as they go past the top of Mauna Loa. This is manifest in the deviations of daily means from a smooth curve that follows the seasonal cycle [Thoning, 1989]. We take into account that successive daily means are not fully independent, the CO₂ deviation on most days has some similarity to that of the previous day. If there is a missing month, its interpolated value is shown in blue.

The last year of data are still **preliminary**, pending recalibrations of reference gases and other quality control checks. Data are reported as a dry air mole fraction defined as the number of molecules of carbon dioxide divided by the number of all molecules in air, including CO₂ itself, after water vapor has been removed. The mole fraction is expressed as parts per million (ppm). Example: 0.000400 is expressed as 400 ppm.

The Mauna Loa data are being obtained at an altitude of 3400 m in the northern subtropics, and may not be the same as the **globally averaged CO₂ concentration at the surface**.

NOTE: Due to the eruption of the Mauna Loa Volcano, measurements from Mauna Loa Observatory were suspended as of Nov. 29, 2022. Observations from December 2022 to July 4, 2023 are from a [site at the Maunakea Observatories](#), approximately 21 miles north of the Mauna Loa Observatory. Mauna Loa observations resumed in July 2023.



Global Monitoring Laboratory

- » U.S. Department of Commerce
- » National Oceanic & Atmospheric Administration
- » NOAA Research

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EXHIBIT F



Explore This Section



Climate Change

From the unique vantage point in space, NASA collects critical long-term observations of our changing planet.

VITAL SIGNS

Show All

Carbon Dioxide**431** parts per million

Global Temperature**1.5** °C since preindustrial

M

NASA applies ingenuity and expertise gained from decades of planetary and deep-space exploration to the study of our home planet. The Earth Science Division operates more than 20 satellites in orbit, sponsors hundreds of research programs and studies, and funds opportunities to put data to use for societal needs. We develop new ways to observe the oceans, land cover, ice, atmosphere, and life, and we measure how changes in one drive changes in others over the short and long term. While listening to and collaborating with industry leaders, international partners, academic institutions, and other users of our data, we deepen knowledge of our planet, drive innovations, and deliver science to help inform decisions that benefit the nation and the world.

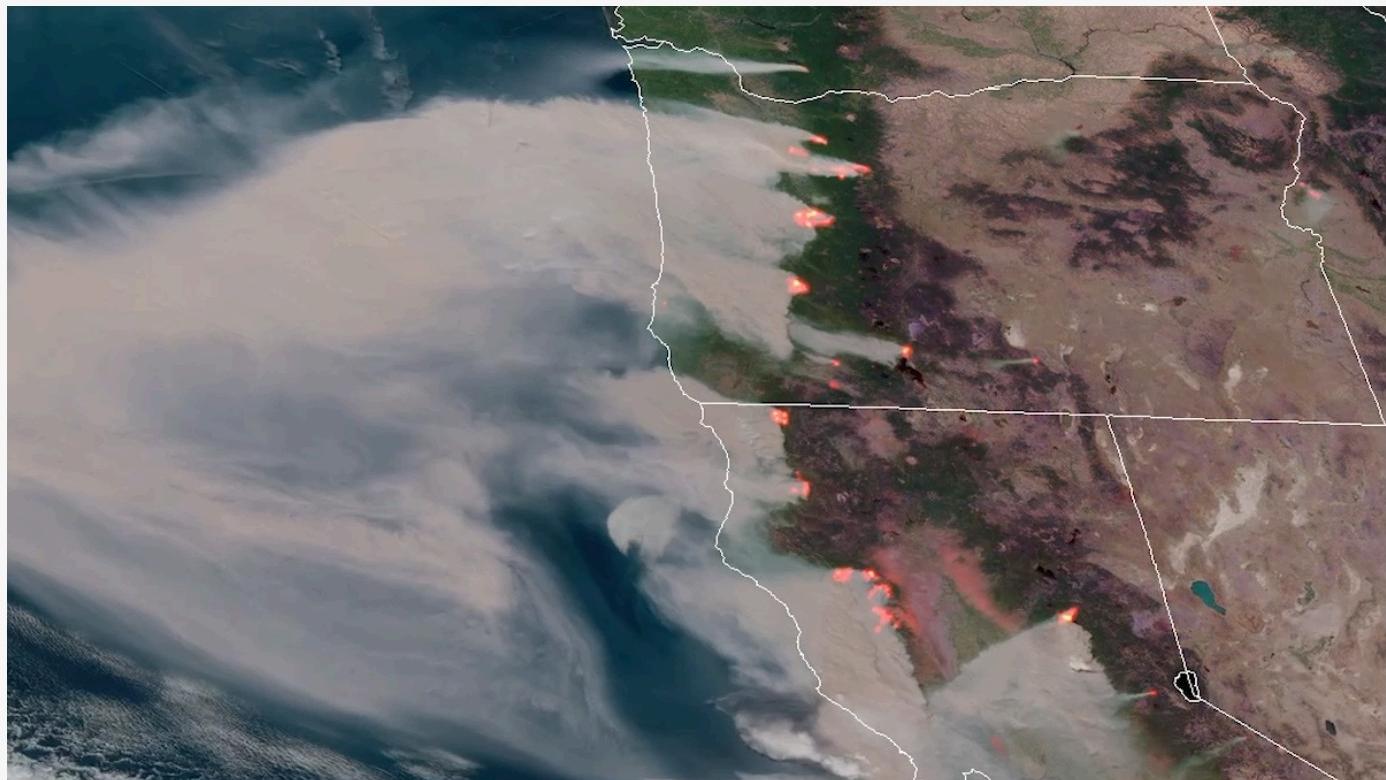
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Wildfires and Climate Change

Earth's warming climate is amplifying wildland fire activity, particularly in northern and temperate forests. When fires ignite the landscape, NASA's satellites and instruments can detect and track them. This information helps communities and land managers around the world prepare for and respond to fires, and also provides a rich data source to help scientists better understand this growing risk.

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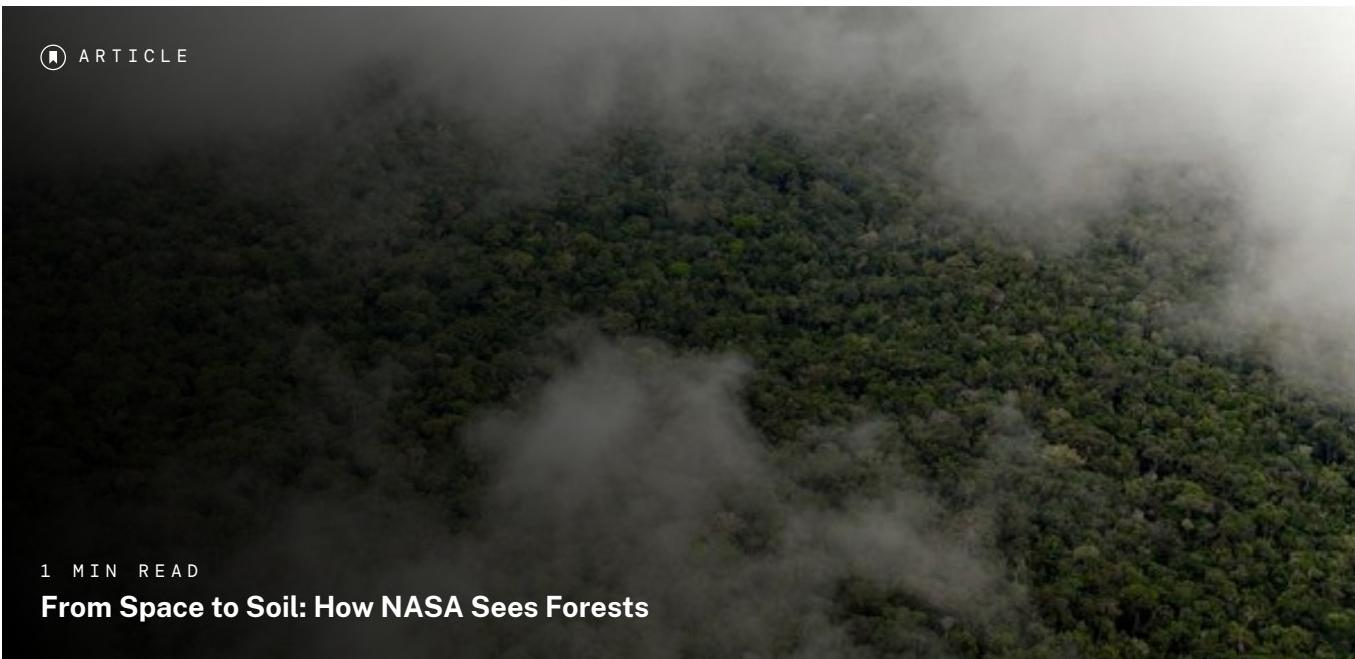
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 BLOG

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Earth Series: From Space to Your Plate



Evidence Causes Effects

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There is unequivocal evidence that Earth is warming at an unprecedented rate. Human activity is the principal cause.

Earth-orbiting satellites and new technologies have helped scientists see the big picture, collecting many different types of information about our planet and its climate all over the world. These data, collected over many years, reveal the signs and patterns of a changing climate.

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Climate change in recent history





Global Ice Viewer

Climate change's impact on ice



Multimedia

Vast library of images, videos, graphics, and more

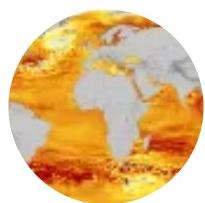


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Climate Data Resources



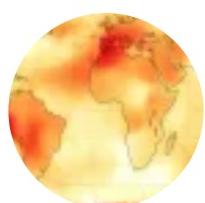
Sea Level Change Observations from Space

Established in 2014, this NASA-sponsored team works to improve the understanding of regional relative sea-level change on a range of timescales. They work with partners to translate the latest science and research into actionable information and to communicate how impacts are increasing at the coast.



NASA Center for Climate Simulation (NCCS)

NCCS provides high performance computing for NASA-sponsored scientists and engineers. The purpose is to enhance NASA capabilities in Earth science, with an emphasis on weather and climate prediction, and to enable future scientific discoveries that will benefit humankind.



GISS Surface Temperature Analysis (GISTEMP)

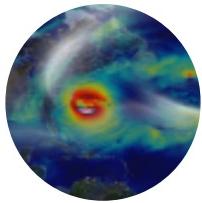
NASA's Goddard Institute of Space Studies assembles one of the world's most trusted global temperature records, using a combination of surface air temperature data acquired by tens of thousands of meteorological stations,





NASA Earth Exchange (NEX)

NEX combines state-of-the-art supercomputing, Earth system modeling, and NASA remote sensing data feeds to deliver a work environment for exploring and analyzing terabyte-to petabyte-scale datasets covering large regions, continents or the globe.



Global Modeling and Assimilation Office (GMAO)

GMAO members perform research, develop models and assimilation systems, and produce quasi-operational products in support of NASA's missions. The Goddard Earth Observing System" (GEOS) family of models is used for applications across a wide range of spatial scales, from kilometers to many tens of kilometers.



World of Change

NASA Earth Observatory has produced a collection of image series that show some features of Earth that have changed over time due to both natural and human-induced causes.

[Learn More](#)



This false-color image, captured by the Landsat 8 satellite, shows Alaska's Columbia Glacier and the surrounding landscape following the more than 20 kilometer retreat of the glacier between 1986 and 2019.

Credit: NASA Earth Observatory



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